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(71) Applicants (for all designated States except US): **XL TECHNOLOGY LTD** [GB/GB]; Gibb House, Kennel Ride, Ascot, Berks SL5 7NT (GB). **BP EXPLORATION OPERATING COMPANY LTD** [GB/GB]; Sunbury Research Centre, Chertsey Road, Sunbury-On-Thames, Middlesex TW16 7LN (GB).

(72) Inventor; and

(75) Inventor/Applicant (for US only): **HEAD, Philip**

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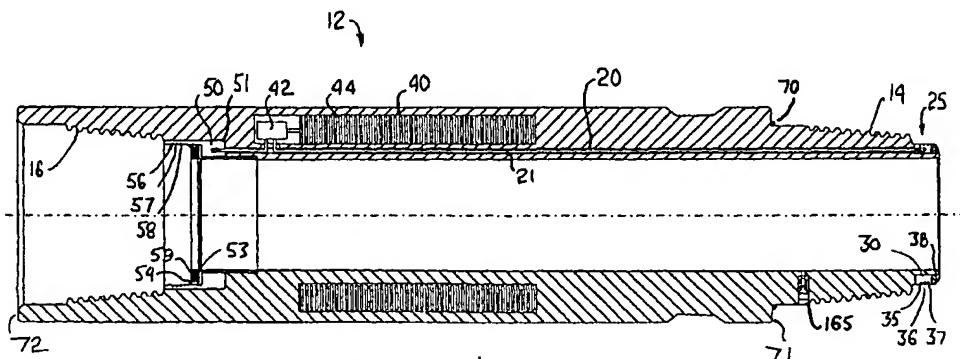
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(54) Title: DOWNHOLE VIBRATING DEVICE



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(57) Abstract: A drill string and powered device system, comprising a drill string which comprises a plurality of drill pipe sections. It includes several conductive drill pipe sections, each conductive drill pipe section having a first end and a second end, and including a conductor. The conductor is connected to a first contact means at the first end and a corresponding second contact means at the second end. The drill string also has a powered tool having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end. The drill string is made up so that conductive drill pipe sections are connected in series above the powered tool such that there is a conductive path through the conductive drill pipe sections to provide power to the powered tool.

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Powered tools for boreholes

The present invention relates to powered tools for boreholes, particularly for use in drill string applications.

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When drilling a borehole, especially deep and/or deviated borehole, the drill string or the drill bit often become stuck in the borehole. A known method of freeing the drill string is to vibrate it. When the drill string becomes stuck, it is known to vibrate the drill string from the surface. The 10 resonant movement of the drill string may allow the drill string to become free from the sides of the borehole.

Such a method is of limited effect, since the vibrations become less effective over distance. It is also known to provide vibration devices 15 attached to the drill string, powered and controlled by the well fluid. The degree of control over these devices is limited to regulating the mud flow, which is inconvenient and ineffective.

The object of the present invention is to provide a convenient system 20 for operating powered tool in association with a drill string.

According to the present invention there is provided a drill string and powered device system, comprising

25 a drill string comprising a plurality of drill pipe sections, including several conductive drill pipe sections, each conductive drill pipe section having a first end and a second end, and including a conductor, this conductor being connected to a first contact means at the first end and a corresponding second contact means at the second end,

a powered tool having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end,

5

the drill string being made up so that conductive drill pipe sections are connected in series above the powered tool such that there is a conductive path through the conductive drill pipe sections to provide power to the powered tool.

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Preferably, conductive drill pipe sections are connected in series below the powered tool such that there is a conductive path from the powered tool to a further powered tool.

15

Preferably the tool includes a second contact means at the second end, and one or more of the drill pipe sections below the powered tool is a conductive drill pipe section, such that a conductive path is provided in the drill string which continues beneath the powered tool.

20

Preferably a second powered tool is connected in series with the drill pipe section, such that a conductive path is provided between the first powered tool and the second powered tool through the conductive drill pipe sections to provide power to the second powered tool.

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Preferably the tool is a vibration tool.

According to another aspect of the present invention, there is provided a tool as herein defined.

A tool system will now be described, by way of example, with reference to the drawings, of which;

Figure 1 is a longitudinal sectional view of a vibration tool;

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Figures 1a and 1b show longitudinal sectional views of connecting the tool;

Figure 1c is a longitudinal sectional view another embodiment of the vibration tool;

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Figure 1d is a longitudinal sectional view another embodiment of the vibration tool;

Figure 2 is a longitudinal sectional view of another embodiment of a

15 vibration tool;

Figures 2a and 2b are longitudinal sectional views of another powered tool arrangement;

20 Figures 3 to 5 are longitudinal sectional views of another embodiment of a vibration tool;

Figure 6a is a cross sectional view of another embodiment of a vibration tool;

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Figure 6b is a cross sectional view of the embodiment shown in figures 3 to 5;

Figures 7 and 8 are longitudinal sectional views of another embodiment of a vibration tool;

5 Figures 9 and 10 are longitudinal sectional views of another embodiment of a vibration tool;

Figure 11 is longitudinal sectional view of another embodiment of a vibration tool;

10 Figure 12a is a diagrammatic representation of the electrical connections of the tools;

Figure 12b is a diagrammatic representation of an aspect of the electrical connections of the tools;

15 Figure 13 is a graph showing relationships of depth, step out and weight on drill bit;

Figures 14 and 15 are section and longitudinal views of a sensor tool;

20 Figure 15a is longitudinal view of another embodiment of a sensor tool;

Figure 16 is longitudinal view of another embodiment of a sensor tool;

25 Figure 17a is a graph showing the relationship between depth and set down force;

Figure 17b is a graph showing the relationships between depth and set down torque;

Figure 18 is a graph showing the relationship between energy and time;

Figure 19 is longitudinal view of another embodiment of a sensor tool;

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Figure 20 is a graph showing the relationships between depth and flow density;

Figures 21 and 22 are longitudinal views of a sensor and receiver tool;

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Figure 23 is a graph showing the relationships between depth and the transmitted and received signals;

Figures 24 and 25 are longitudinal views of a pump tool;

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Figures 24a and 24b are longitudinal views of the pump in use;

Figure 26 shows a drill string incorporating pump tools installed in a bore hole;

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Figures 27a and 27b are longitudinal views of a valve tool;

Figures 28a and 28b are longitudinal views of another embodiment of a valve tool;

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Figure 29 is longitudinal view of several tools incorporated in a drill string;

Figure 30 is a diagrammatic representation of the electrical connections of the these tools;

Figure 31 is longitudinal view another arrangement of several tools incorporated in a drill string;

- 5 Figure 32 is a diagrammatic representation of the electrical connections of the these tools;

Referring to figure 1, the vibrating tool 12 is generally tubular, and has a female receiving thread 16 at one end, and a corresponding male 10 thread 14 at the opposite end. These threads correspond to the male and female threads of the drill pipe joints making up the drill string.

The vibrating tool has three bores (only one of which can be seen) drilled longitudinally inside the tool wall, equally spaced around the radius 15 of the tool.

Referring also to figures 1a and 1b, the bore 20 opens at the male end at a region 25 forward of (considering forward to be towards the right in the figure) and proximal to the thread 14. The bore emerges at the 20 female end of the drill pipe forward of (again considering forward to be towards the right in the figure) and proximal to the thread 16.

The tool wall also includes an cylindrical cavity 40, radially outwards from the bores. A driving unit 42 and cylindrical vibrator 44 are 25 located in the cavity. A communicating passage links the bore to this cylindrical cavity. Conductors are introduced along the length of the bores. The conductor 21 in the bore communicating with the cylindrical cavity includes a break where driving unit is connected in series. The driving unit is connected across the vibrator.

Where the bores open at the female end of the tool 12, a female connector 50 is attached, the conductor terminating in this female connector. If necessary, a recess 51 is provided to accept the female connector 50. The female connector is annular, and includes three annular conductive rings 56, 57, 58 having surfaces exposed on its inner circumference. Each of the three conductive rings are connected respectively to one of the three conductors. The female connector includes a radial shoulder 53, this shoulder having a metal sealing surface 54.

10 Incorporated in the radial shoulder is an annular seal 59, such as an elastomeric seal.

Where the bore opens at the male end of the tool 12, a male connector 30 is attached, the conductor 21 terminating in this male connector. If necessary, a recess is provided to accept the male connector 30. The male connector is annular, and includes three annular conductive rings 35, 36, 37 having surfaces exposed on the outer circumference of the male connector. Each of the three conductive rings are connected respectively to one of the three conductors. A metal sealing ring 38 is also included in the male connector.

The cylindrical vibrator 44 comprises a series of annular piezo-electric elements. In order to effect vibration, the driving unit 42 applies an oscillating voltage to the piezo-electric devices, and the piezo-electric elements contract and relapse in accordance with the voltage oscillation.

25 The oscillations in the piezo-electric elements cause the vibrating tool to vibrate.

The drill pipe joints feature similar bores, conductors and male and female connectors. When series of these drill pipe joints are connected above and below the vibrating tool, the rings of each male connector and the rings of each female connect make contact, such that three conductive paths through the drill string are provided. The male end of the tool includes a shoulder region 71 and radial elastomeric seal 70. When the male end is introduced into the female end of a drill pipe section (which includes a corresponding profile similar to a profile 72 on the female end of the tool), a metal to metal seal is established, the elastomeric seal providing further sealing. Another metal to metal seal is provided between the sealing ring 38 of the tool and the sealing surface and elastomeric seal 59 (similar to the sealing surface 54) on the drill pipe section.

The male end of the drill pipe section 10 includes a pressure release valve 165 forward of the shoulder 71. When the male end of the tool 12 is introduced to the adjacent drill pipe section, lubrication grease on the threads is pressurised as it becomes trapped in a decreasing volume between the metal to metal and elastomeric seals 38, 53, 59 of the male and female connectors 30, 50 on the one hand, and the metal to metal seal between the shoulder 71 of the male end of tool 12 and the end 72 of the female end of drill pipe section 12, and the elastomeric seal 70 on the other hand. The pressure release valve allows excess lubricating grease to escape when a certain pressure is reached. This pressure is set such that it does not stress the seals when the environmental pressure is low, but is sufficient to afford protection to the seals when the environmental pressure is high. It will be realised that position of the pressure release valve may be varied.

It will be seen that other vibrating means could be included in the vibrating tool, such as magnetostrictive elements, or even a mechanical

oscillator. For example, referring to figure 1c, a mass 55 is in face contact with a cam member 252 having annular cammed surface comprising two ramps. The mass is constrained so that it cannot rotate in the annular cavity 254, and as the cammed surface 252 rotates relative to the mass, the mass is 5 displaced along one of the ramps and away from an anvil 258 as the cammed surface is rotated. Forward of the mass are Belleville springs 256, which become compressed and energised as the cammed surface displaces the mass. Upon completion of the 180° rotation, the mass 55 reaches the end of a ramp and the mass is released, to be impelled by the Belleville 10 springs 256 into the anvil, and the impact is transmitted through the drillstring. This process is repeated every for 180° rotation of the cammed surface relative to the mass

Referring to figure 1c, a hammer 253 is connected to a rotating shaft 15 256 via a keyway 257, such that as keyway 257 is rotated relative to the hammer 253, the hammer is moved away from an anvil surface 258. As in the previous example, the hammer 253 compresses a resilient member 256 as the hammer is so moved. When a 360° rotation of the inner shaft relative to the hammer has been completed (for a keyway containing one whole turn 20 over the circumference of the inner shaft) the hammer 253 is released, the resilient member 256 urging the hammer 253 forcefully into the anvil surface 258.

Referring to figures 3 to 5, an alternative embodiment of the 25 vibration tool 20 comprises a tubular member 22 having a male thread 14 and a corresponding female receiving thread 16, and a sleeve 65 fitted around the tubular member. The sleeve is accommodated by a waist 45 in the tubular member, so that the outer surface of the sleeve is generally flush with the largest outer diameter of the tubular member 22. Polyurethane

roller bearings 24 allow the sleeve 65 to rotate about the tubular member
22. A chamber 66 is defined between an annular cavity in the sleeve 65 and
the outer surface of the waist 45 of the tubular member. In this cavity is
located an annular hammer 63, biased forwards by a spring 64. The
5 hammer includes a peg 47, which engages with a helical keyway 49 in the
surface of the tubular member.

To operate the vibration tool, an electrically operated rotation means
causes the sleeve 65 to rotate upon its bearings 24, and as it does so, the peg
10 47 is forced around the keyway 49, drawing back the hammer 63, and
compressing the spring 64. When the hammer reaches its hindmost
position, as shown in figure 4, the keyway 49 becomes shallower pushing
the peg 47 out of the keyway. The sleeve 65 is no longer constrained by the
peg 47, and the hammer 63 is urged forward by the spring 64, the peg
15 travelling outside of the keyway, as shown in figure 5. The hammer strikes
an annular anvil 54 that extends around the circumference of the waist of
the tubular member, and comes to rest. In coming to rest, the exchange of
momentum from the hammer 63 to the anvil 54 causes a percussive
vibration to extend along the drillstring.

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Referring also to figure 6b, three sets of three traction wheels 60 are
disposed at 120° intervals around the circumference of the sleeve 65. These
wheels include a disengageable ratcheted mechanism 62 so that that sleeve
is not propelled backwards up the drillstring to dissipate the momentum
25 imparted by the hammer. The wheels, when engaged, also prevent the
drillstring from rotating. A different number of wheels, such as two sets of
three wheels as shown in figure 6a, could instead be provided.

The vibration tool, as in the previous example, features a male connector 70 disposed forward of the male thread 25, and a female connector 72 located forward of the female receiving thread 30, the male and female connectors each including three corresponding axially spaced annular contact rings at regions 71 and 73 respectively. As for the previous embodiment, the vibration tool also includes conductors 21 between the male and female connectors to form conductive paths along the body of the tool. The vibration tool can thus be included between conductive drill pipe section as previously described, and draw the power (at a junction 23) necessary to cock the hammer from one or more of the conductors.

Preferably, the tool draws a three phase power supply using all three of the conductors.

Referring to figures 7 to 8, a further embodiment of the vibration tool features a central anvil 80 located midway along the body of the tool, a front annular hammer 81 and a rear annular hammer 91 disposed in the cavity 42 between the sleeve 40 and the tool body 22. The rear hammer 91 includes a spring 92 biasing the hammer forward, while the front hammer includes a spring 82 biasing the front hammer rearward. The rear hammer includes a peg 93 towards the rear of the rear hammer, which runs in a rear keyway 94, while the front hammer includes a peg 83 towards the front of the hammer which runs in a front keyway 84. Both keyways are helical, though the threads are cut in opposite senses (for example, the front keyway has a right-handed screw, whilst the rear keyway has a left handed screw).

To operate the tool, the sleeve 41 is rotated so as to draw the front hammer 81 forward and the rear hammer 91 backward. When the hammers are at their cocked positions (i.e. the front hammer is at its most forward position, and the rear hammer is at its hindmost position), either hammer may be fired by operating a front or a rear peg actuator 85, 95 which draw the

respective pegs from the keyways. Thus, a forward or a rearward momentum may be imparted to the drill string as desired. After one of the hammers has been fired, either the remaining hammer may be fired, or the fired hammer may be reset, by turning the sleeve. The remaining hammer 5 remains in its cocked position, the peg remaining in a radial groove at the end of each keyway. Figure 8 shows the rear hammer 91 being fired with the front hammer 81 in the cocked position, whilst figure 7 shows the front hammer 81 being fired with the rear hammer 91 in the cocked position.

10 The vibrating device may thus be used to impart a forward impulse when the drill string is being advanced through the borehole, and a backward impulse when the drill string is being withdrawn from the borehole (and may also become stuck or snagged by the borehole sides).

15 As in the previous embodiments, this vibrating tool includes the conductors between the male and female connectors to form conductive paths along the body of the tool. The vibration tool can thus be included between conductive drill pipe section as previously described, and draw the power necessary to cock the hammer from one or more of the conductors.
20 Alternatively, but less preferably, power may be supplied through a cable of other conductor means disposed along the drillstring. The tool may be operated either downhole, or out of hole.

Referring to figures 9 to 11, in another embodiment the vibrating
25 tool includes two hammers either side of a common anvil (as for the previous embodiment). Three channels 100, 101, 102 are spaced along the length of the tubular body of the vibration tool, each of which include gates capable of stopping the throughflow. The channels allow communication between the bore of the tool and the cavity. A axial linking channel 104

connects the foremost and hindmost channels 100 102, but does not communicate with the middle channel 101.

The hammers 81, 91 are held in their cocked positions against coiled
5 springs by pegs 83, 93 which engage in radial grooves 86, 96 in the waist portion of the tubular body. In order to fire a hammer, the relevant peg is slid from the groove by an electric actuator, so that the hammer is no longer constrained, and is urged into the anvil 54.

10 To reset the hammer or hammers, an orifice 110 is released through the bore of the drill string, which comes to rest and engages in a profile 111 provided in the bore of the vibration tool 20. The orifice constricts the flow, and thus creates a pressure differential across itself. When well fluid is flowing from left to right as shown in the picture, the fluid to the left of
15 the orifice 110 will be at a higher pressure than the fluid to the right of the orifice. The part of the cavity 42 between the hammers 81, 91 and the anvil 54 is thus in communication with a relatively high fluid pressure (via the middle channel 101), while on closing the foremost channel 102, the regions of the cavity between each hammer 81, 91 and that hammer's
20 spring 82, 92 is in communication with a relatively low fluid pressure via the hindmost channel (the hindmost and foremost channels 100, 102 communicate with these regions via grooves not here shown for the full range of the hammers movement). The fired hammer is thus displaced by the pressure difference, compressing the spring, until the peg engages with
25 the radial groove.

When it is intended to fire the hammer, the fluid pressure through the bore is reduced. In turn, the pressure differential across the orifice 110 is also reduced, and so the force displacing the hammer to its cocked position

reduces. When the peg release is activated, the spring causes the hammer to strike the anvil. The peg release is preferably activated by some control means in response to control signals from the surface.

5 The peg release could also be activated whilst the peg is at some point along the helical path. Since the spring will have less energy, the hammer will impart a smaller impulse to the anvil. In this way, different impulses may be chosen as required. The tool may be fitted with hammers of different weights and springs of different characteristics in order to vary
10 the characteristics of the imparted force.

Thus any of the vibrating tools 102 described may be installed at a convenient point along the drill string 98, as shown in figure 12a, using drill pipe joints carrying conductive paths and having male and female
15 connectors as described above, the tools tapping power along a series of points 103 and, drawing, say, 1 kW of power from a total consumption that could typically be between 20 and 200 kW. The vibrating tool may thus be operated from the surface by passing current through the appropriate conductive path. It will be seen that several such vibrating tools may be
20 installed at convenient intervals along the drill string, since the male end of the vibrating tool provides a connection for the conductive paths in a suitable drill pipe joint fitted upon it. Referring to figure 12b, the each tool preferably draws a three phase power supply using a connection 105, 106,
107 for each of the three conductors 113, 114, 115.

25

The vibration tool may also be actuated by engaging the traction wheels so that the sleeve cannot rotate relative to the borehole, and rotating the drill string. There will then be a relative rotation between the hammers and the tool body, causing the pegs to be drawn back by the helical

keyways. Alternatively, hydraulic or other activation and control means could be used.

Figure 13 shows a graph indicating the weight on bit obtained when 5 using vibrating tools disposed along the drill string at the positions indicated by the bars. Line shows the weight on bit with respect to depth and step out, which decreases approximately exponentially under conventional conditions without any vibration applied. When the vibration tools are used, the jars given by the tools ensure that the weight on bit is 10 30% of the total weight when the step out is 10 000 m, whereas the weight on bit would be expected to be approximately 10% at the same step out at this point without utilising the vibrating tools.

Dedicated sensor assemblies may be included, such as is shown in 15 figure 14. This sensor assembly 120 is generally tubular in a similar manner to the hammer tool and the drill pipe, and includes conductors and contacts in a three phase system as previously described for the hammer tool and drill pipe sections so that a conductive path for power and signals is provided along the drill section. The sensor assembly is made up of an 20 upper member 121 and a lower member 122, the region where the upper and lower members abut on the inner surface being sealed with a collar 124 having two o-ring seals 125, 126. The sensor member includes measuring instruments such as a 3-axis accelerometer 127, a hydrophone 128, a weight sensor 129 (which measures force along the axis of the drill string) and a 25 torque sensor 130 (which is visible in figure 15), the weight and torque sensors being positioned at the engaging region of the upper and lower members so as to measure the relevant forces acting between them. The measurements taken from the sensors are gathered by a processor 132,

which transmits the data along the conductive path 119 to the surface of the borehole (e.g. by superimposing a signal on the power supply).

Ideally, a sensor assembly 120 is incorporated near each hammer
5 tool. In this way, the drill string operators can measure the magnitudes of the weight 135 (as shown in figure 17a) and torque 137 (as shown in figure 17b) are distributed along the length of the drill string, and thereby deduce the cumulative distribution of weight 136 or torque 138 along the length of the drill string. Regions where the weight or torque (or the change in
10 weight or torque) for particular sensors are high (at 140) may indicate sites where the drill string has become stuck to the borehole wall. The hammer tool or tools closest to that region may be fired in order to produce a shifting impulse. In this manner, the drill string is freed from the side of the borehole in a convenient and efficient manner, whilst the drill string is
15 subjected to less jarring than would occur if the hammer tools were made to fire indiscriminately. The signals from the sensors are transmitted to the surface, and the correct sequence of activating the vibration tools is initiated, the signals being conveniently transmitted by telemetry means in order to effectively free the drill string. Alternatively, processing means
20 disposed in the drill pipe could process the signals, and determine and activate the appropriate firing of the vibration tools automatically.

Referring to figure 15a, the sensor assembly may include a neck section 123 protected from the main flow through the bore hole annulus by
25 a perforated barrier layer 118. In this neck section a set down weight and strain gauge bridge arrangement 116 and a torque, and strain gauge bridge 117 are included. Other sensors, such a scintillating flow sensor described below, may be included.

Sticking in the drill string can also be deduced using the sensor assemblies' hydrophones 128. Referring to figure 18, the hammer tool associated with a particular sensor assembly is fired, producing a high signal 141. As the sound is carried along the drill pipe, periodic signals 142 5 are detected by the hydrophone, due to a proportion of the original sound wave being reflected at the coupling of each drill pipe section. In regions where the borehole wall has become stuck to the drill pipe, the drill pipe resist the propagation of the sound wave and a large proportion of the original sound wave is reflected to the hydrophone as a signal 143. Using 10 the periodic nature of the drillpipe coupling elements, the regions where sticking is occurring can be conveniently deduced, and the hammer tool in that region can be activated to help free the drill string. The drill string can then be advanced, and weight applied to the bit, more effectively.

15 Referring to figure 16, in another embodiment of a sensor, rather than a conducting path running through the drill string and connected as previously described, the sensor 120 includes a length of cable 219 arranged in a wound tubular formation inside the inner bore of the sensor. A collar 124 which seals the upper and lower members of the sensor also 20 helps support the cable 219. One end (the lower end) of the cable 219 passes through a bore in this collar 124, and is secured by it. This part of the cable 219 terminates somewhat beyond the bottom of the sensor (to the right when looking at the figure) with a jack 218. The opposite end (the upper end) of the cable 219 leads freely from the tubular formation of the 25 main portion of the cable 219, and terminates in a plug 219. The coil may be frangibly secured, for example with silicone. The sensors shown are as for the sensor previously described.

When the sensor 120 is fitted in the drill string, and drill pipe sections are fitted above it in the drill string, the upper end 219 of the cable is threaded through the added drill pipe sections as they are added. The cable separates and unwinds from the wound tubular formation 219 to

5 accommodate the increasing distance the cable has to reach, the cable being secured at its passage through the collar 124. The length of the unwound cable is sufficient to extend to a further assembly including a similar cable wound tubular cable formation. This may be another sensor, or a hammer tool, and ideally features a jack on the lower end cable in a similar manner

10 to the jack 218 of the sensor 120 depicted. The jack on the antecedent assembly is connected to the socket 219.

The sensors 132, 127, 128 and 129 tap the cable 219 in order to receive control signals and power if necessary, and to transmit signals. It

15 will be seen that the sensor assemblies, and the hammer tools, can tap into their corresponding cable lengths in a similar manner, the different signals being multiplexed as necessary.

Referring to figure 19, a sensor assembly 120 may include other

20 types of sensor. Shown here are scintillating chambers 172 disposed in the upper part 121 of the sensor assembly for determining the density and/or flow rate of the fluid *a* in the borehole annulus, for example by detecting irradiated particles in the well fluid. Using such transmitted data, a profile of the fluid density (measured along the y-axis) along the length of the

25 disposed drill string (measured along the x-axis) may be built up in real time, as shown in figure 20. A non-uniform density profile will indicate if insufficient cuttings are being cleared from the borehole, and the drill bit speed and fluid flow may be regulated accordingly.

If regions of the borehole wall persist in impeding the progress of the drillstring, the drillstring may be raised so that the drill bit makes a wiper trip to clear the troublesome region (e.g. by breaking up material that may have fallen in from the borehole wall). Since the position of the region can 5 be calculated, the drill string need only be raised to that region, saving time that would be expended making a full wiper trip had the position of the region not been known. A drill string having only a plurality of sensor assemblies (i.e. without any hammer tools) could also be used in borehole operations, as it will be seen that it is advantageous to locate a troublesome 10 region and so dispense with a full wiper trip even without installing hammer tools. The sensors distributed along the drill pipe may also be utilised for receiving signals transmitted from a source remote to the borehole, for example a sonde at another location.

15 Drill pipe joints having conductive paths through need not of course be fitted below the lowermost tool in the drill string, and this lowest tool need not provide a male end connector or even have a conductive path running the entirety of its length. Referring to figure 2, the conductive path could be continued all the way through to an electrically powered drill bit, 20 and the vibrating tool 120 provided adjacent to the drill bit supporting assembly 18 which includes the drill bit 15. The drill bit supporting assembly 18 includes a female receiving thread and female connectors similar to that of the vibrating tool as previously described, so that the conductors of the vibrating tool continue through to the drill bit supporting 25 assembly 18 and provide power for the drill bit. It has been found that such vibration provided in the vicinity of the drill bit aids the 'weight on bit' exerted by freeing the drill string from the sides of the borehole. Other powered tools may be incorporated into the drill string in a neighbouring manner such that between the tools there are no sections of drill pipe.

Referring to figures 2a and 2b, a electric telescopic assembly 201, 203 may be located directly behind the drill bit 15, knuckle joint 208, near but sensors and motor 205, so that any displacement of the drillstring, in
5 particular due to the vibration or hammer means located in the drill string, may be compensated by contraction or expansion of the telescopic assembly. The control of the telescopic assembly may be effected by sensing displacement of the drill string above the assembly, or it may be controlled by signals from other tools that are about to cause the drill pipe's
10 displacement.

Referring to figure 21, a sensing system may be included behind the drill bit 15, and drill bit assembly 210, a source drill pipe section 220, and a plurality of receiver drill pipe sections 230. As the drill string advances
15 down the borehole, receiver drill pipe sections 230 are added to at the top of the drill string so as to increase the length of the drill string.

Referring to figure 2, the source drill pipe section and the receiver drill pipe sections are generally tubular in form. The source drill pipe
20 section includes a retractable transmitter 222 and a retractable off-set ram 224. The transmitter 222 includes an annular magnetoresistive member to produce a seismic signal, the annular configuration allowing the through bore of the drill string to remain unobstructed. Each receiver drill pipe sections also includes a retractable combined off-set ram and sensor 228,
25 disposed in an alternating arrangement as shown.

When the drillstring has reached an appropriate depth, the drilling is stopped and the retractable transmitter 222 and retractable off-set ram 224 of the source drill pipe section are extended, and the retractable combined

off-set ram and sensor 228 of each of the receiver drill pipe 230 sections is extended. Each combined off-set ram and sensor 228 has a variable extension, and continue to extend until a particular resistive force is encountered. This force is set so that when the off-set rams, the transmitter 5 of the source drill pipe section and the sensors of the receiver drill pipe sections are all extended, the transmitter and sensors are pressed closely to the side of the borehole, ensuring a good transfer of acoustic signals between the transmitter and the rock, and the rock and the sensors.

10 Referring to figure 23, the rams 224, 228 are be provided at intervals 228b along the drill string. These are fired in sequence, and reflected signals from features in the rock return to the receivers 228a, the time differences between the received signals allowing the location of the geological features causing the reflection to be calculated.

15

When the seismic data has been thus gathered, the off-set ram and sensors and the transmitter of the source drill pipe section are all retracted, and the drill string may be advanced further down the borehole or may be withdrawn from borehole.

20

The source drill pipe section and each transmitter drill pipe sections has a female receiving thread at one end of its body, and a corresponding male thread at the opposite end, and provides a conductive path down the drill string as previously described, as of course the other (i.e. non-sensing 25 or transmitting) drill pipe sections placed between the source and receiver assemblies and any other tools combined with them. It will be released that one or more receivers provided in a drill pipe sections could be disposed without source drill pipe section, and still pick up signals generated by a

remote source. Equally, a source drill pipe section could be disposed by itself in order to provide signals for remote receiving means.

Referring to figures 24 and 25, the pump drill pipe section 430
5 comprises a tubular body 400, a stator 410 disposed inside the body, and an impeller or positive displacement pump section 420 disposed inside the stator 410. The body of the pump drill pipe section, and the stator, includes inlets 402, 403, which communicate with the cavity 404 in which the impeller sits. The impeller features a bore 422 through its shaft 424, and
10 this bore communicates with the cavity via shaft inlets 426. The body 400 of the pump drill pipe section 430 includes a stator coil 406, which acts upon an rotor coil 408 disposed around the impeller shaft 424. The ends of the impeller shaft 424 are open to the bore 440 of the drillstring both above and below the pump drill pipe section.

15

In operation, electrical power is provided to the stator coil 406, which causes the rotor coil 408 and the impeller shaft 424 to rotate on bearings between itself and the stator 410. The fins 425 of the impeller increase the fluid pressure along the cavity 404 (towards the left of the figure 25), driving fluid through the shaft inlets 426. Fluid from the annulus between the drillstring and the borehole sides flow through the inlets 402, 404 to replace this fluid. The fluid in the impeller shaft 424 flows out through both open ends of the impeller shaft, so that inside the drillstring an upward flow is created above the pump drill pipe section 430,
20 and a downward flow is created below the pump drill pipe section. In the annulus 442 outside the drillstring, a downward flow is created above the pump drill pipe section, while an upward flow is created below the pump
25 drill pipe section.

This mode of circulation exposes the open hole to a lower circulation pressure which allows more open hole to be drilled before casing is required.. The pump and packer system shown in figure 24 may be used to control the wellbore pressure, for example to carry out underbalanced

- 5 drilling. Referring to figure to 24a, fluid from the annulus 602 between a drillstring 610 and the borehole 600 above the packer 604 and pumps 606 is directed through an upper port 608 through the drill string 610 below the packer and pump assembly 604, 606. Mud returning from the drill bit 612 is then directed by a lower port 614 up through the drill string 610 above 10 the packer and pump assembly 604, 606. Distributed pressure sensors monitor the down hole pressure, and by controlling the entry and exiting of fluid from the annulus 602 and drillstring 610 above the packer and pump assembly respectively, the pressure below the packer and pump assembly can be maintained at its optimum value. This results in improved wellbore 15 stability. Using a hydraulic ram system 616 behind the drillbit 612, the weight on bit can also be accurately controlled below the packer and pump assembly.

- The downhole pressure may also be controlled using the upper and 20 lower ports . Referring to figure to figure 24b, a formation test may be carried out by halting the drilling and closing the upper port 608 to isolate the well bore annulus 602, while fluid continues to be pumped from the formation below the packer and pump assembly 604, 606. This reduces the pressure (due to the hydrostatic weight of the drilling mud in the annulus), 25 stimulating production from the formation. The upper port 608 may be opened to increase the hydrostatic pressure below the packer and pump assembly 604, 606 and so kill the tested formation.

As in the case of the previously described tools, the packer and pump tool has corresponding male and female threaded ends, and a connection arrangement for providing conductive paths along the drill string.

5 Referring to figure 26, more than one pump drill pipe section could be disposed in the drill pipe section 450. Here, a depleted reservoir means that fluid can only be supported up to a certain level 454 in the borehole 452, so that pumping from the surface cannot be employed. This arrangement can also be used in deepwater regions where dual density
10 drilling is to be considered.

Each of the pumps may be operated and actuated independently from the surface, for example by including a control means on each pump, and superimposing or otherwise including a control signal with the power
15 supply. The control signals could be included on one of the three conductors, while each pump draws three phase power to actuate the movement using all three of the conductors.

Different types of pump may be incorporated into tubular sections so
20 as to fit into a drillstring utilising the principles herein disclosed. In particular, the pump drill pipe section may be adapted so that the impeller forces fluid in one direction along the bore of the drill string, by having the impeller shaft closed at one end. Also, the pump drill pipe section could act directly solely on the fluid in the drillstring bore, without accepting fluid
25 from the borehole annulus.

Referring to figures 27a and 27b, the valve drill pipe section comprises a tubular body 300, in which is disposed a shaft member 310 and a seal member 320. The shaft member has a tubular part 312 which is set in

the tubular body 300 of the valve drill pipe section, and shaft 314 which is supported in a axially centrally aligned position, so that an annulus exists between the shaft and the tubular part of the shaft member, apart from the supporting strut or struts (which are not here shown). The seal member 320
5 comprises a support portion 324, which is tubular and features a thread upon its inner surface, and a profiled portion 322, is also generally tubular, and has a profiled bore. The profiled portion has a thread upon its outer surface which corresponds to and engages with the thread upon the support portion.

10

The support portion 324 lies against the inner surface of the tubular body 300 of the valve drill pipe section, and is constrained against axial movement, but is free to rotate with respect to the tubular body . A stator coil 330 installed in the tubular body acts upon a rotor coil 332 in the
15 support portion so as to turn the support portion. The profiled portion 322 includes lugs (not here visible) which run in longitudinal grooves on the inner surface of the shaft member, and constrain the profiled portion against rotation. Thus, when the support portion 324 is rotated, the profiled portion 322 moves axially relative to the support member.

20

The profiled member 322 includes a gradually constricted bore portion. As the profiled member is moved downwards towards the shaft 314, the shaft enters the constricted portion so that the effective cross section of the bore through the valve drill pipe section is reduced. When
25 the profiled portion reaches its lowermost position, as shown in figure 27b, the shaft abuts the constricted portion and entirely blocks the profiled portions bore. In this way, the valve drill pipe section may be operated so as to regulate or stop the fluid flow through the valve drill pipe section, and hence the flow through the bore of the drill string. Lugs 326 constrain the

downward movement of the profiled portion 322 (and a similar mechanism may be used to constrain the upward movement of the profiled portion).

Referring to figures 28a and 28b, in another embodiment the shaft 5 314 of the shaft member 310 includes a through bore 328. The region between outer surface of the shaft member 310 and the inner surface of the tubular portion 300 of the shaft member 310 is closed by a plate 327. Inlets 328, 329 are provide through the wall of the shaft member 310 and the tubular body 300 of the valve drill pipe section communicating with the 10 annulus between the drillstring and the borehole sides (hereinafter the 'borehole annulus') and the annulus between the shaft and the tubular portion of the shaft body (hereinafter the 'valve annulus').

With the profiled portion 322 in its uppermost position, it will be 15 seen that well fluid may flow between the drill string bore beneath the valve drill pipe section, the drill string bore above the valve drill pipe section, and the borehole annulus. As the profiled portion 322 is lowered in the manner described above, the valve annulus is sealed by the constrained portion of the profiled portion being occluded by the shaft 314. This closes the 20 communication between the borehole annulus and the drillstring bore.

Such a valve drill pipe section could also or alternatively be provided with valve gates 330 set in the walls of the tubular body of the valve drill pipe section, to block the communication between the borehole annulus and 25 the valve annulus.

Other configurations giving different types of flow control are also possible; for example, rather than a constrained section, a centrally aligned pin element supported by a strut may be provided with the profiled member

to engage with the hollow shaft, so that the flow between the drillstring below the valve drill pipe section and drillstring above the valve drill pipe section on the one hand, and the flow between the borehole annulus and the drillstring above the valve drill pipe section on the other hand, may be
5 regulated independently by the gate valves and the movement of the profiled member respectively.

As in the case of the previously described tools, each valve
drill pipe section has corresponding male and female threaded ends, and a
10 connection arrangement for providing conductive paths along the drill
string.

It will be realised that several such valve drill pipe sections may
be included in the drill string to achieve a desired result, in particular they may
15 be fitted in combination with a plurality of pump means disposed along the
drillstring. In particular, when used in a deep borehole, particularly when a
lateral shaft is being drilled, different drill fluid densities may be used, and
this system can be advantageously used to circulate only certain sections of
the borehole, for example circulating only the fluid in the substantially
20 lateral section whilst not circulating the fluid in the substantially vertical
section.

Each of the valves may be operated and actuated independently from
the surface, for example by including a control means on each valve, and
25 superimposing or otherwise including a control signal with the power
supply. The control signals could be included on one of the three
conductors, while each valve draws three phase power to actuate the
movement using all three of the conductors.

Referring to figures 29 and 30, a drill bit 15 having an adjustable knuckle joint 208 is driven by an electric motor 205. Sensors are included in an assembly 206 between the motor and the drill bit to monitor the drilling environment. Behind the drill bit 15 and electric motor 205 is 5 located an electrically powered and controlled adjustable traction tool 212, which uses data provided by an incorporated load cell. Immediately behind the traction tool is situated a pump 214 and inflatable packer and flow tester tool 216 for inflow testing. These tools draw power from the power lines as previously described, that is, by a series of junctions tapping into the power 10 line provided along the drill string. Control signals to the tools, and sensing data from the tools, are multiplexed and superimposed on the power line. Referring to figures 31 and 32, similar groups of tools, here comprising a motor and pump 232, a load cell and traction tool 234, and a further motor 236, may be provided at intervals over the length of the drill string, drawing 15 power and signals from the power line as previously described.

It will be seen that other types of tool provided with the appropriate male and female threads, and in particular other types of vibration tools, seismic sources, sensors, pumps and valves, may be fitted in series instead 20 of or in addition to a vibrating tool using such conducting drill pipe joints, and differing arrangements of conductive path through the drill pipe joints may be utilised to supply power to a powered tool within the principles herein disclosed. An individual tool may draw power from a single conductor, or it may draw from all three conductors, whose supply may be 25 phased in order to provide a three phase power source.

The tools so disposed at points along the drill string may be selectively operated by including a control signal superimposed upon the power supply, which activates and regulates the driving unit of the tool.

Further, in some cases subassemblies of a particular tool system may be separately controlled. For example, in the case of the receiver and transmitter tool, it may be advantageous to control individual receivers, transmitters, and off-set rams individually. Alternatively, additional 5 conductive elements could be used for a dedicated control signals. Receivers, sensors or other feedback devices included with the tools may add a return signal to the conductor, so that information may be gathered and decoded on the surface, or information exchanged between tools.

Claims

1. A drill string and powered device system, comprising
 - 5 a drill string comprising a plurality of drill pipe sections, including several conductive drill pipe sections, each conductive drill pipe section having a first end and a second end, and including a conductor, this conductor being connected to a first contact means at the first end and a corresponding second contact means at the second end,
 - 10 a powered tool having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end,
 - 15 the drill string being made up so that conductive drill pipe sections are connected in series above the powered tool such that there is a conductive path through the conductive drill pipe sections to provide power to the powered tool.
- 20 2. A system according to claim 1, wherein conductive drill pipe sections are connected in series below the powered tool such that there is a conductive path from the powered tool to a further powered tool.
3. A system according to either previous claim, wherein the tool
 - 25 includes a second contact means at the second end, and one or more of the drill pipe sections below the powered tool is a conductive drill pipe section, such that a conductive path is provided in the drill string which continues beneath the powered tool.

4. A system according to claim 3, wherein a second powered tool is connected in series with the drill pipe section, such that a conductive path is provided between the first powered tool and the second powered tool through the conductive drill pipe sections to provide power to the second powered tool.
 5. A system according to any previous claim wherein the tool is a vibration tool.
- 10 6. A system according to any of claims 1 to 4, wherein the tool includes a valve means, and a sealing means, such that the annulus above the sealing means may be selectively isolated from the borehole beneath the sealing means.
- 15 7. A system according to claim 6 wherein the tool includes a pump.
8. A system according to any previous claim wherein the powered tool has a wall which includes at least one bore, the bore having a conductor disposed inside it
- 20 9. A system according to any previous claim wherein the powered tool has a wall which includes at least one bore, the bore having a conductor disposed inside it
- 25 10. A system according to any previous claim, wherein the first end of the tool has a first two metal radial sealing surfaces and the second end of the drill pipe section attached to the first end of the tool has a corresponding second two metal radial sealing surfaces.

11. A system according to any of claims 3 to 8, wherein the second end of the tool has a second two metal radial sealing surfaces and the first end of the drill pipe section attached to the second end of the tool has a corresponding first two metal radial sealing surfaces.

5

12. A system according to previous claim wherein the first and second ends of the tool include corresponding threads, said threads providing the corresponding first and second metal radial sealing surfaces.

10 13. A system according to any previous claim wherein the first contact means and the second contact means are provided by corresponding conductive rings coaxial with the drill pipe.

15 14. A system according to any previous claim wherein the tool includes three bores each including a conductor, and these conductors respectively connected to a first three conductive rings at the first end, and a second three conductive rings at the second end, such that three conductive paths.

15. A drill string according to any previous claim wherein there is included a pressure balancing means capable of varying the pressure of the sealed volume to reduce the pressure difference between the sealed volume and the environment.

20 25 16. A drill string according to any of claims 1 to 4, including a sensor means having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end.

17. A drill string according to claim 14 wherein the sensor means includes a transmission means capable of transmitting control signals transmitted along the conductive path.
- 5 18. A drill string according to either of claims 14 or 15 wherein there are included displacement means that are reversibly activatable in order to urge the sensor means towards the side of a bore hole.
- 10 19. A drill string according to any of claims 1 to 4, including a transmitter means having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end.
- 15 20. A drill string and sensor means system according to any previous claim wherein there are included displacement means that are reversibly activatable in order to urge the transmitter means towards the side of a bore hole.
- 20 21. A drill string according to any of claims 1 to 4 comprising a pump means having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end.
- 25 22. A drill string according to claim 19 wherein the pump means comprises a tubular body which features said first end and said second end, the tubular body incorporating a stator coil, and a water propelling means including a rotor coil such that the stator coil is capable of causing the rotor coil and the water propelling means to rotate.

23. A drill string according to any of claims 1 to 4 including a valve means having a first end and a second end corresponding to the first and second end of the drill pipe sections, including a contact means at the first end.

5

24. A drill string and valve system according to claim 23 wherein the valve means comprises a tubular body having said first end and said second end, there being a stator coil fixedly attached to or incorporated in the tubular body, the valve means further including a moveable sealing member 10 including a rotor coil, such that the stator coil is capable of rotating the rotor coil.

25. A method of determining the length of some or all of the conductive path according to any previous claim wherein an electric signal is applied to 15 the conductive path, the time taken for the signal to travel along some or all of the conductive path is recoded, and the distance calculated according to the characteristics of the conductive path.

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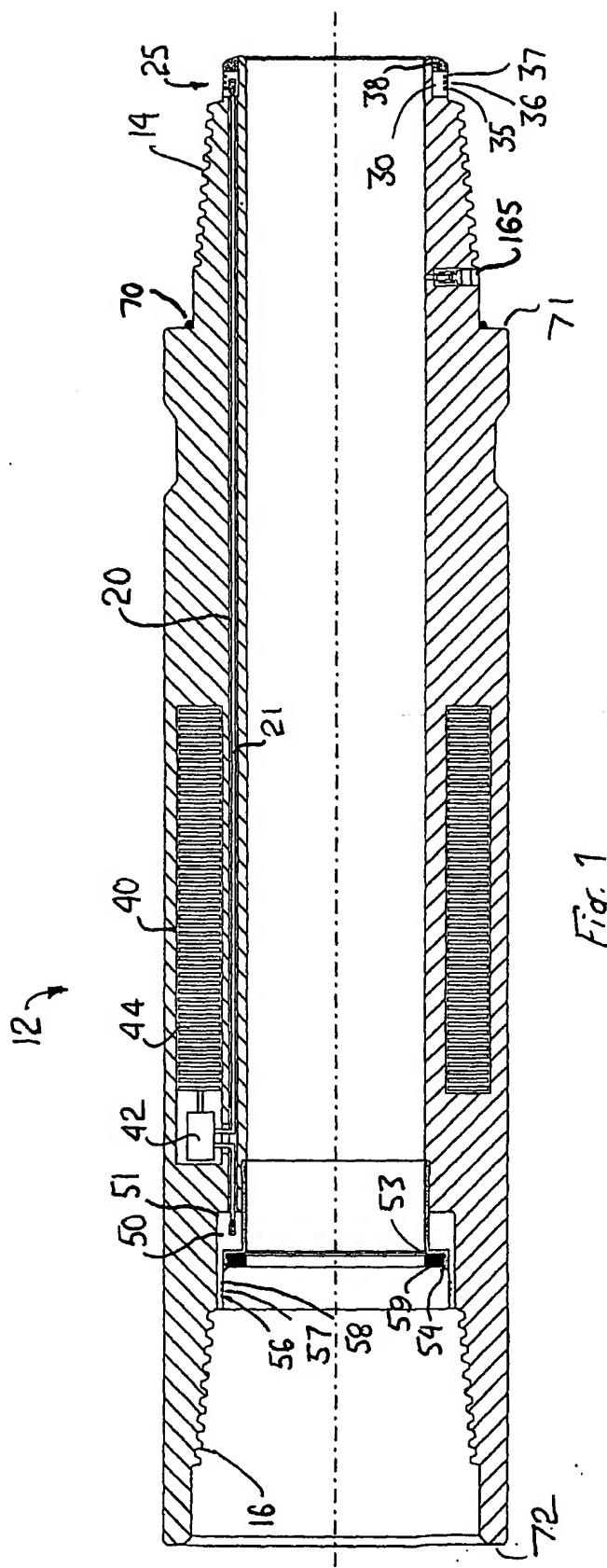


Fig. 1

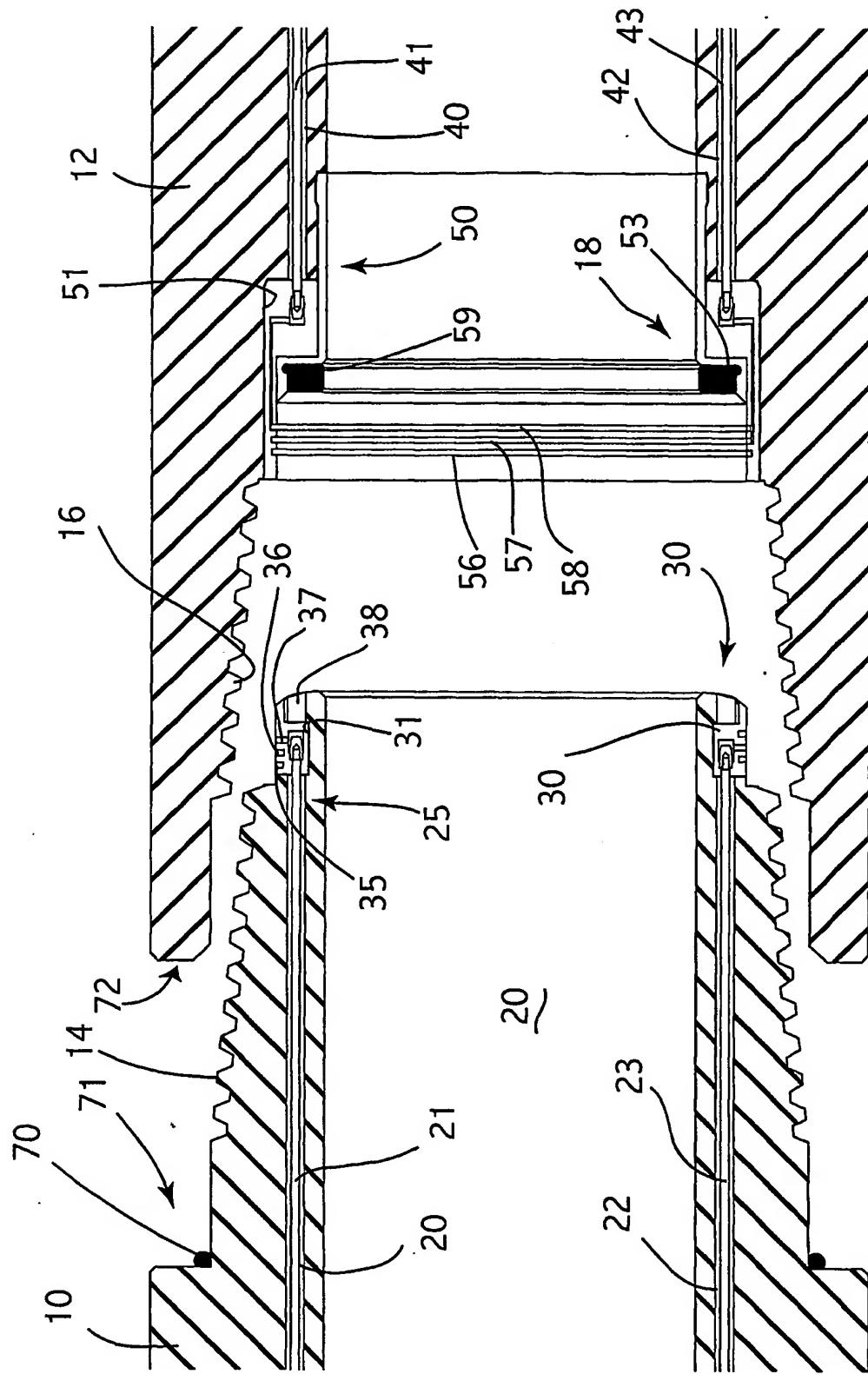


Fig. 1a

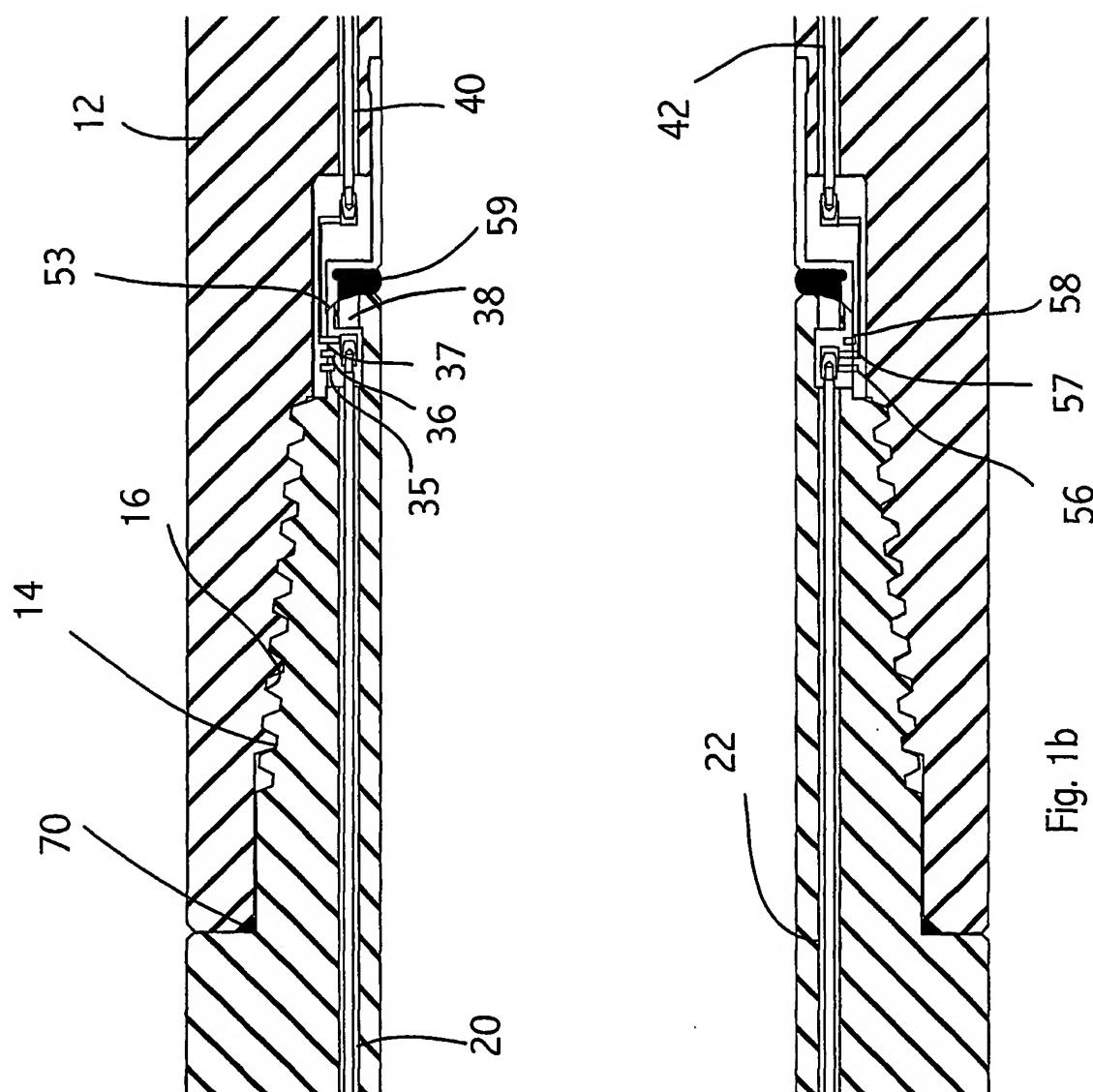


Fig. 1b

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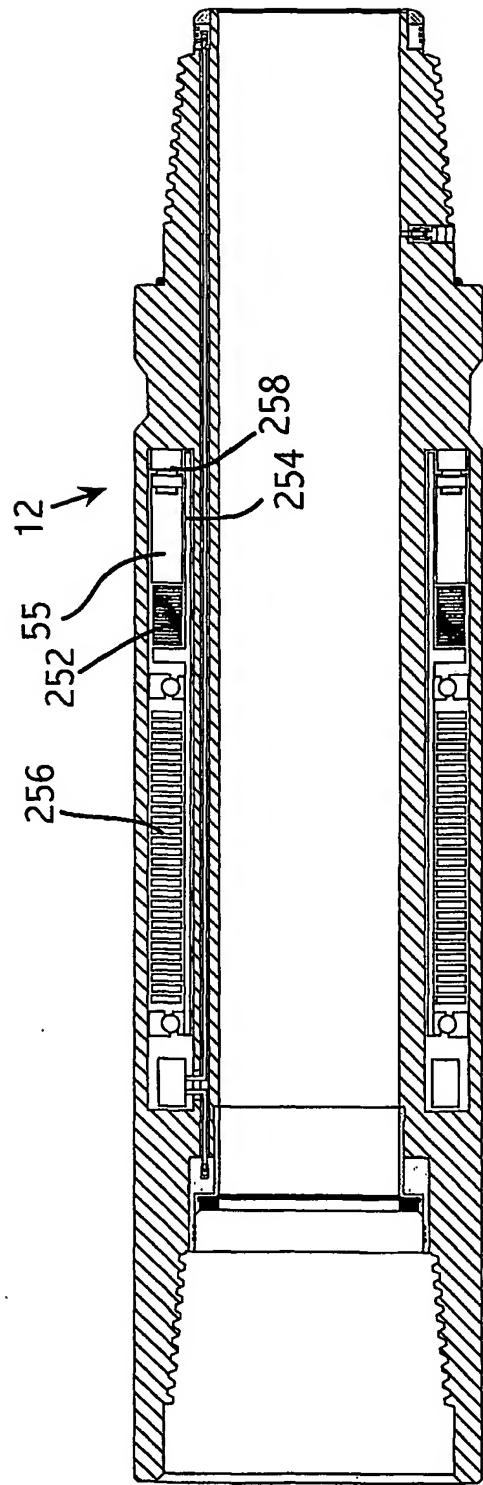


Fig. 1c

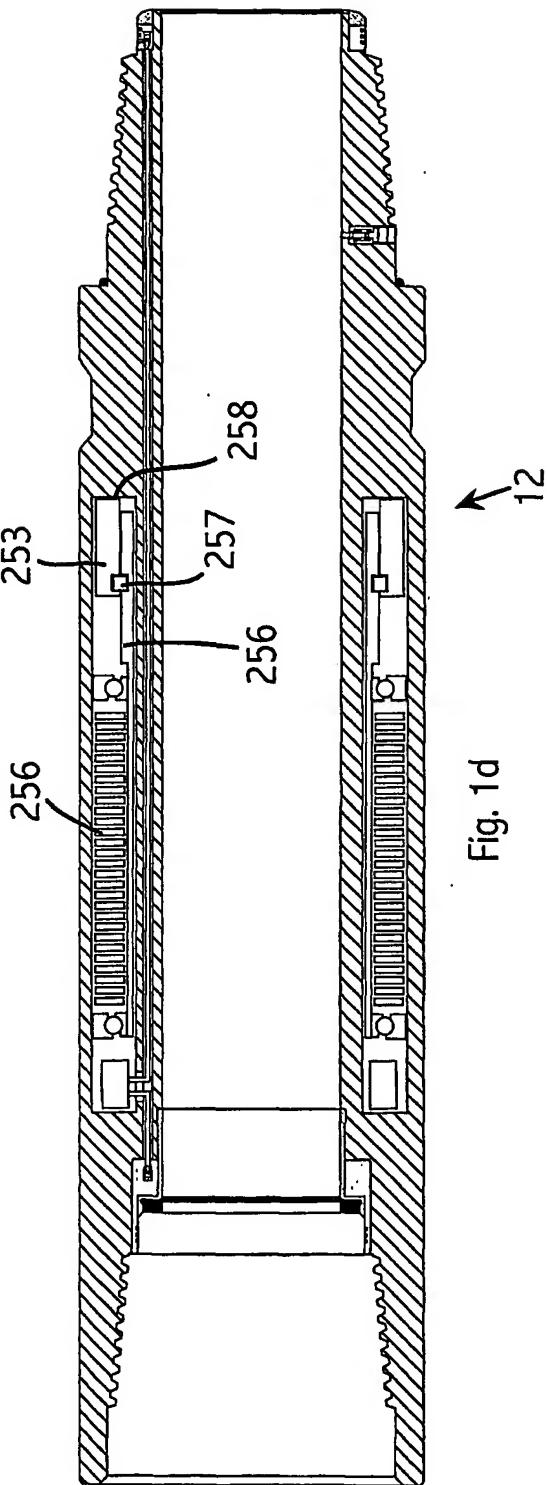


Fig. 1d

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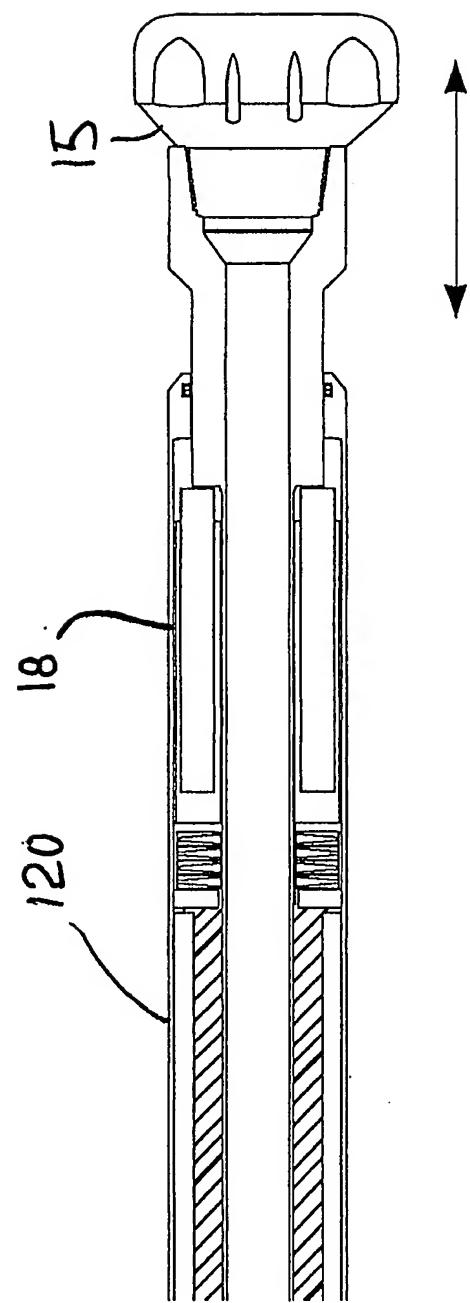


Fig. 2

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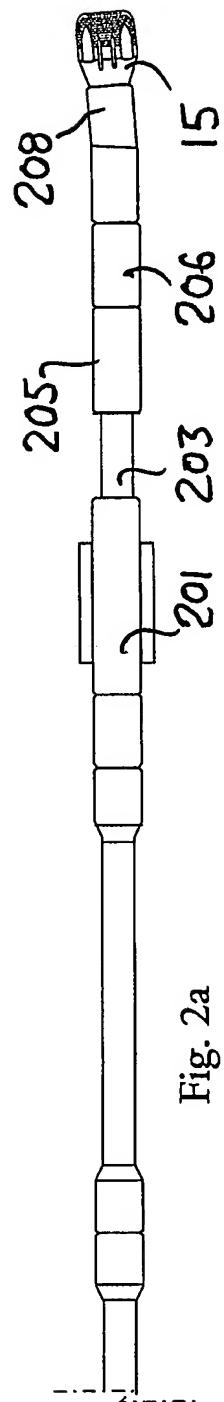


Fig. 2a

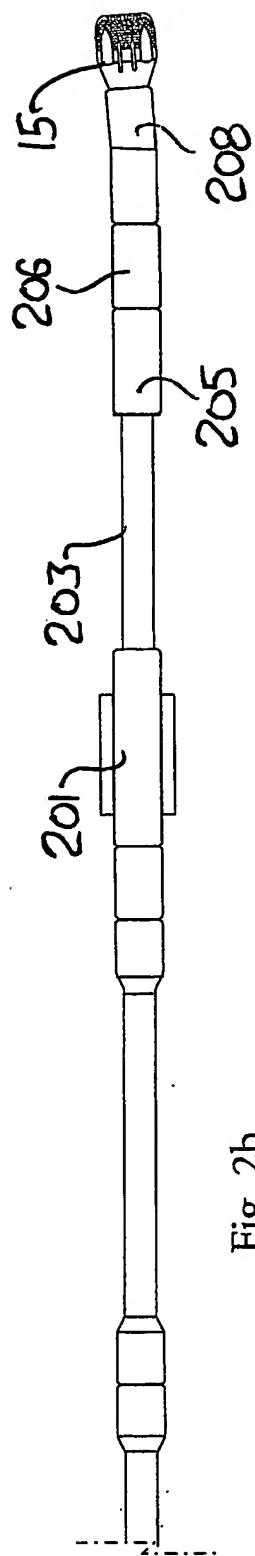


Fig. 2b

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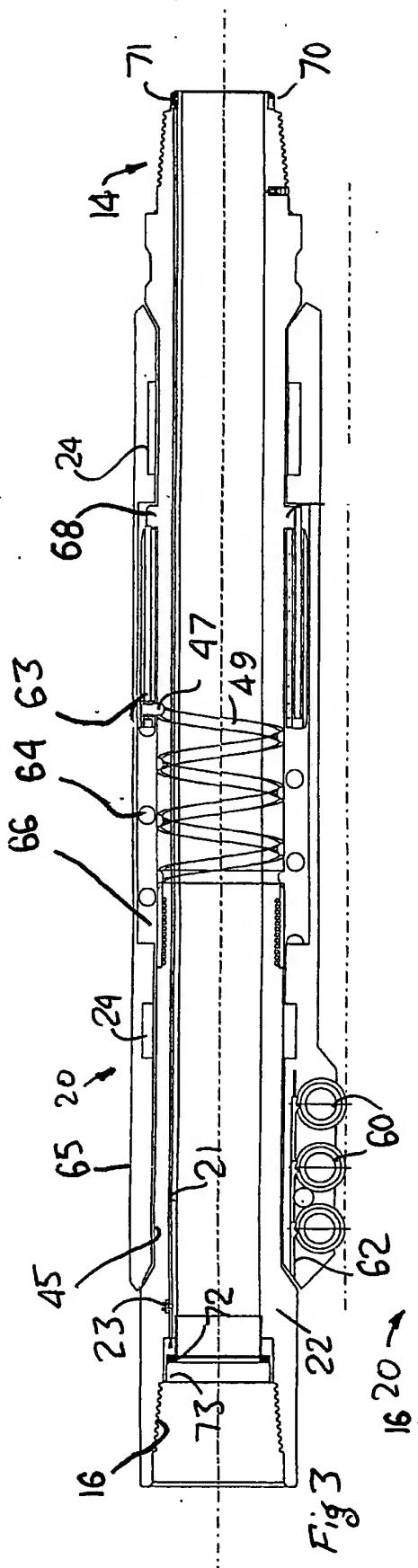


Fig. 3

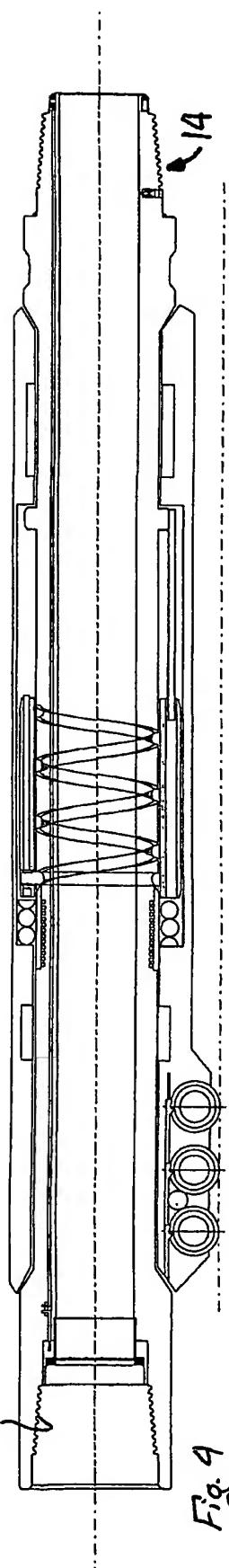


Fig. 4

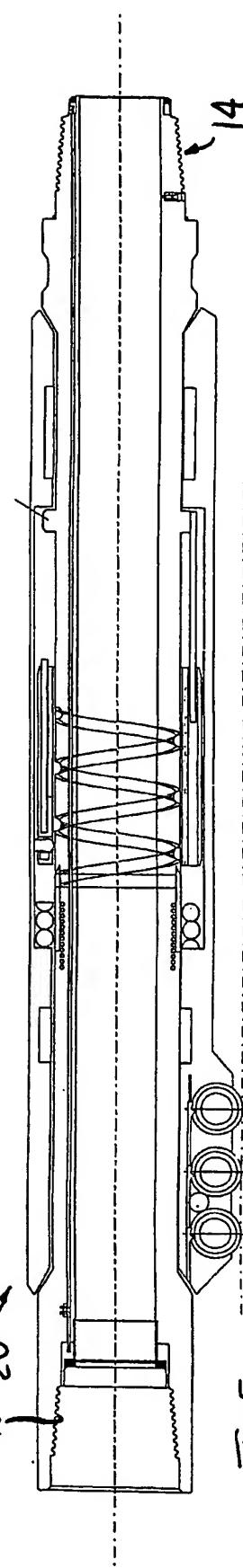


Fig. 5

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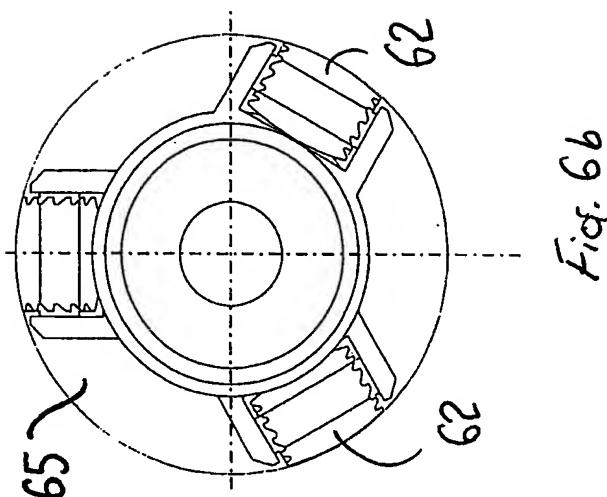


Fig. 6b

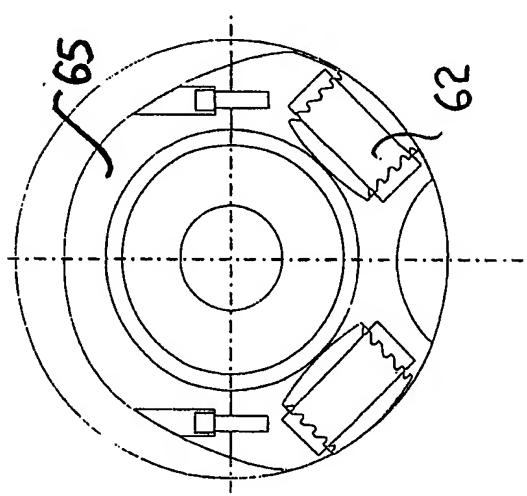


Fig. 6a

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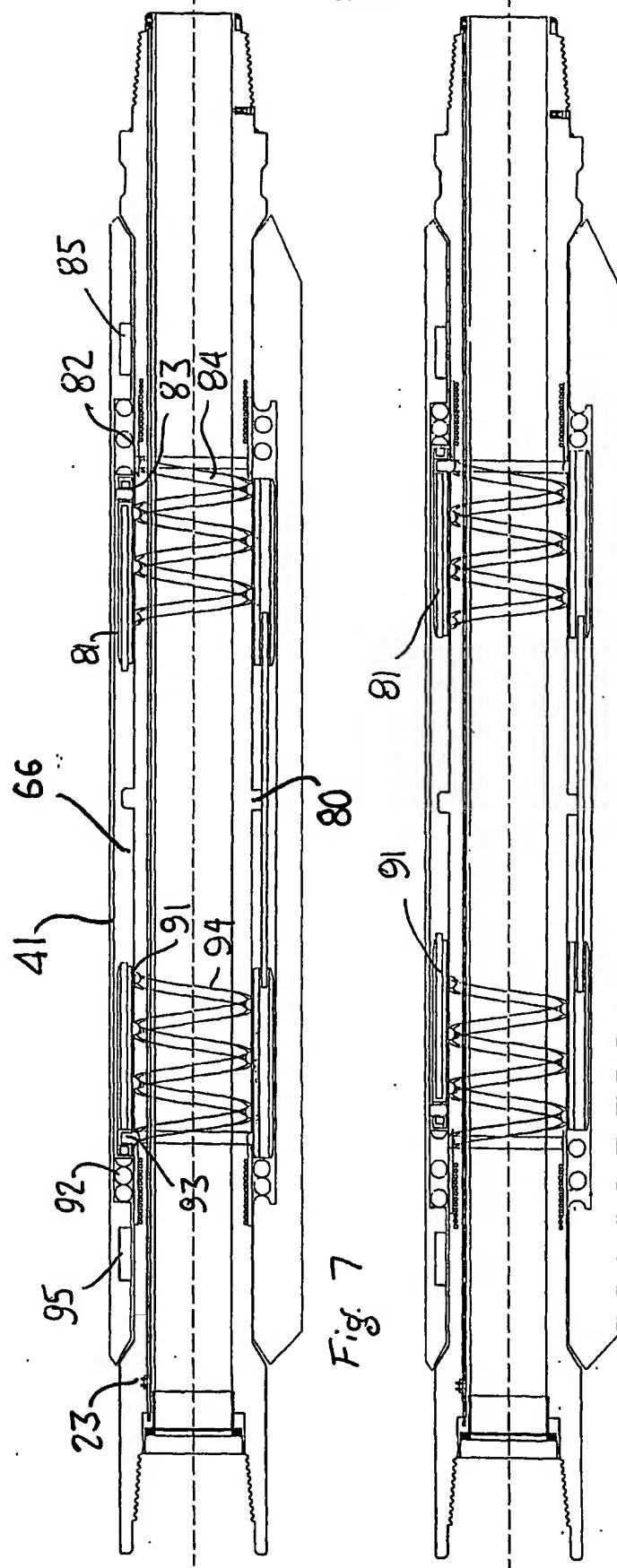


Fig. 7

Fig. 8

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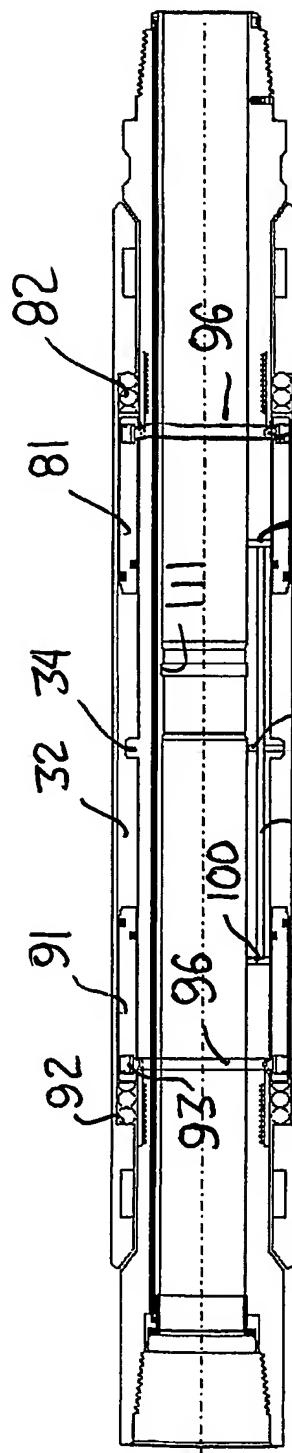


Fig. 9

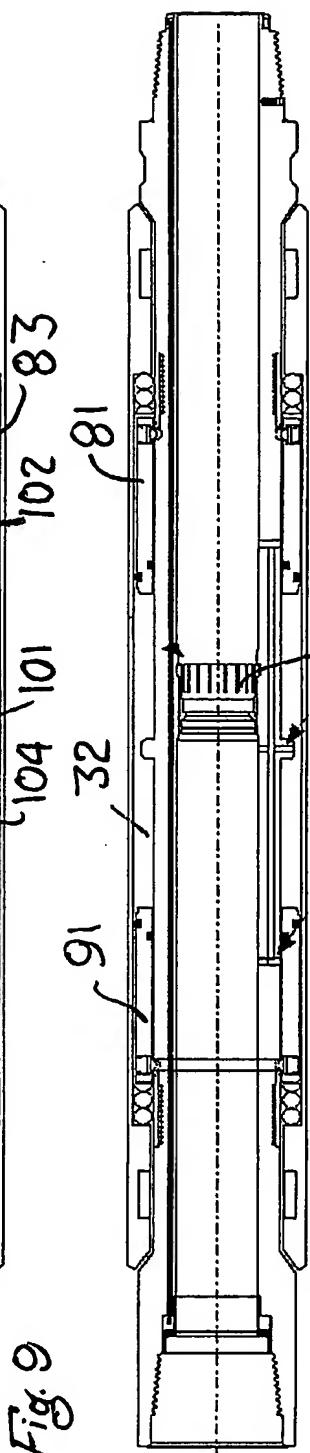


Fig. 10

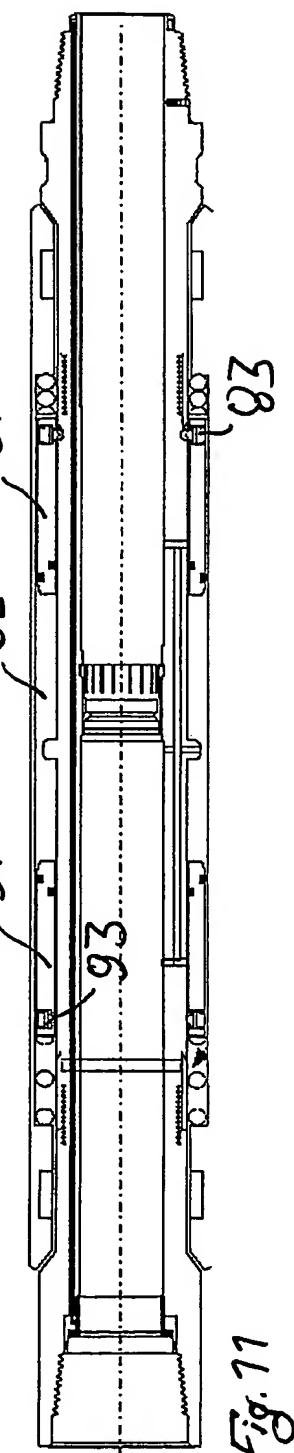


Fig. 11

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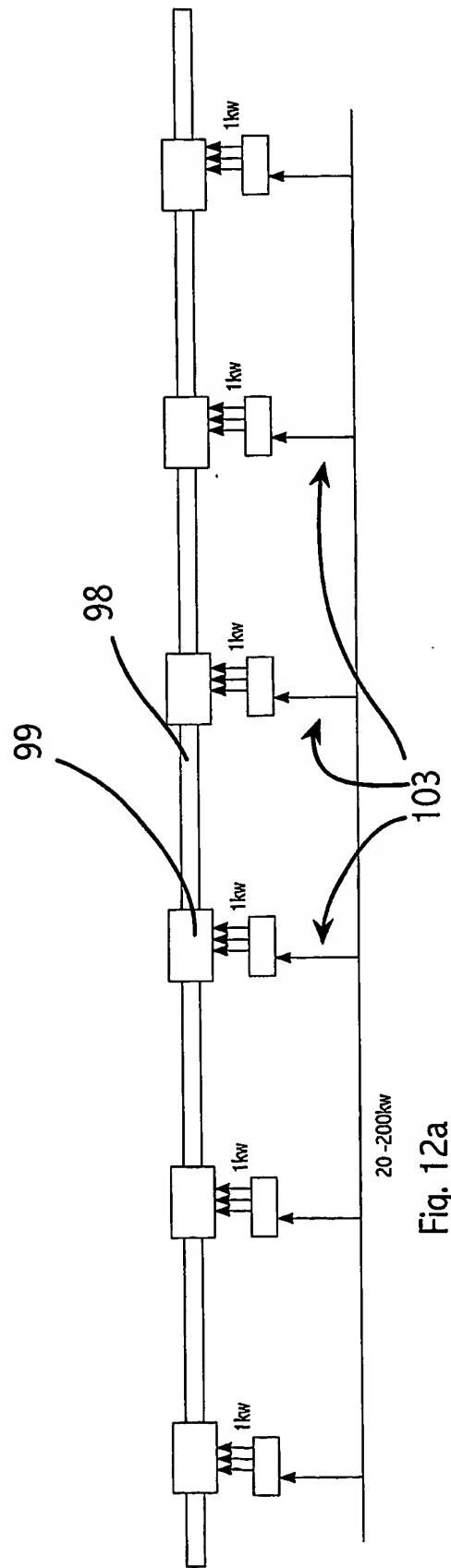


Fig. 12a

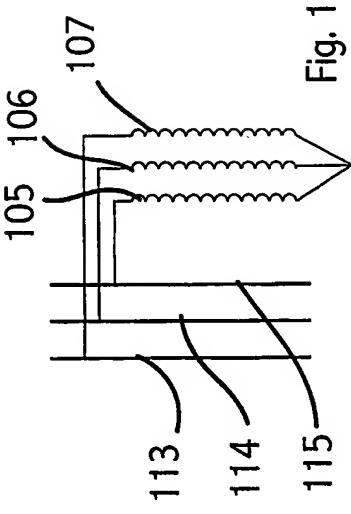


Fig. 12b

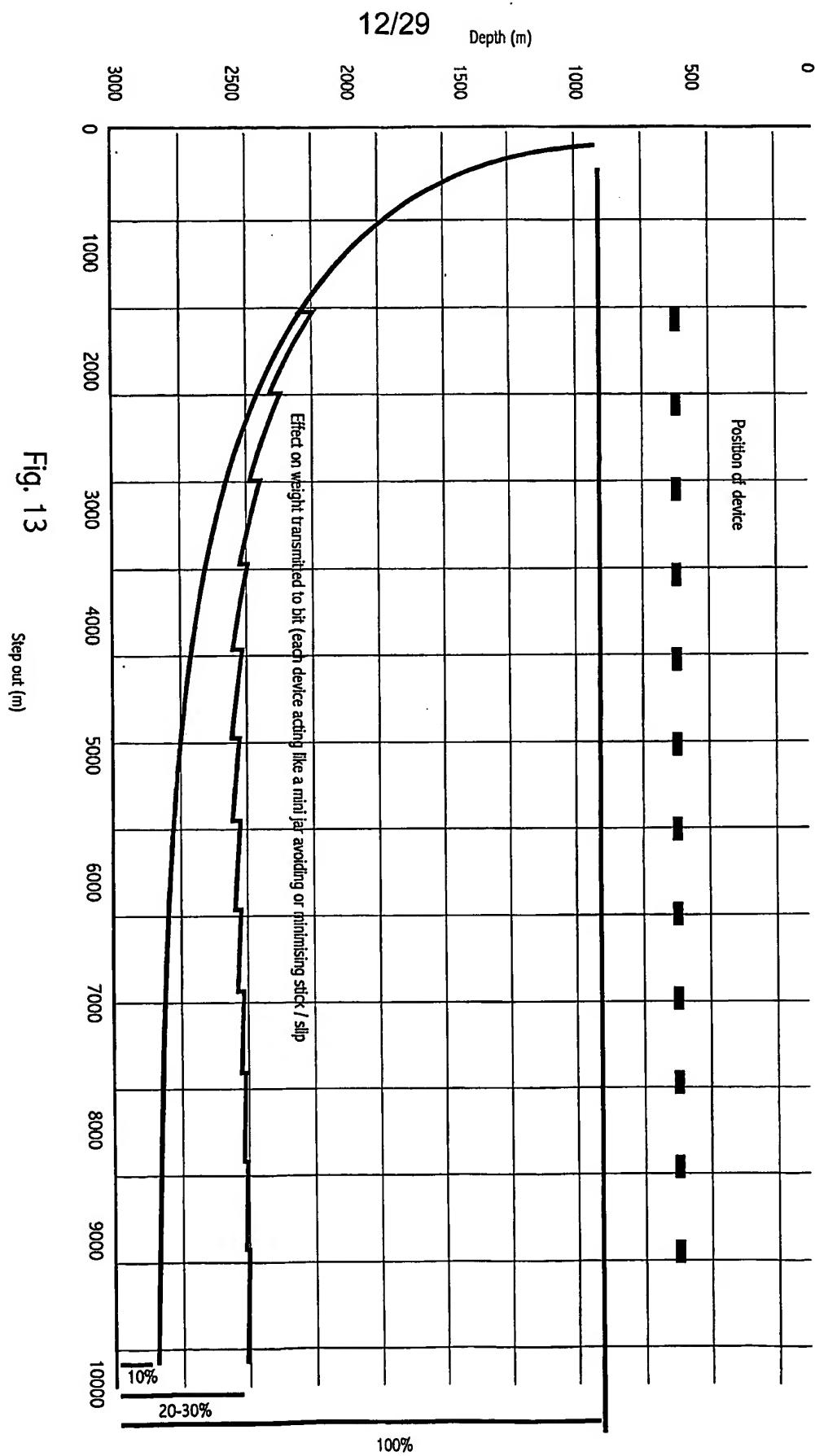


Fig. 13

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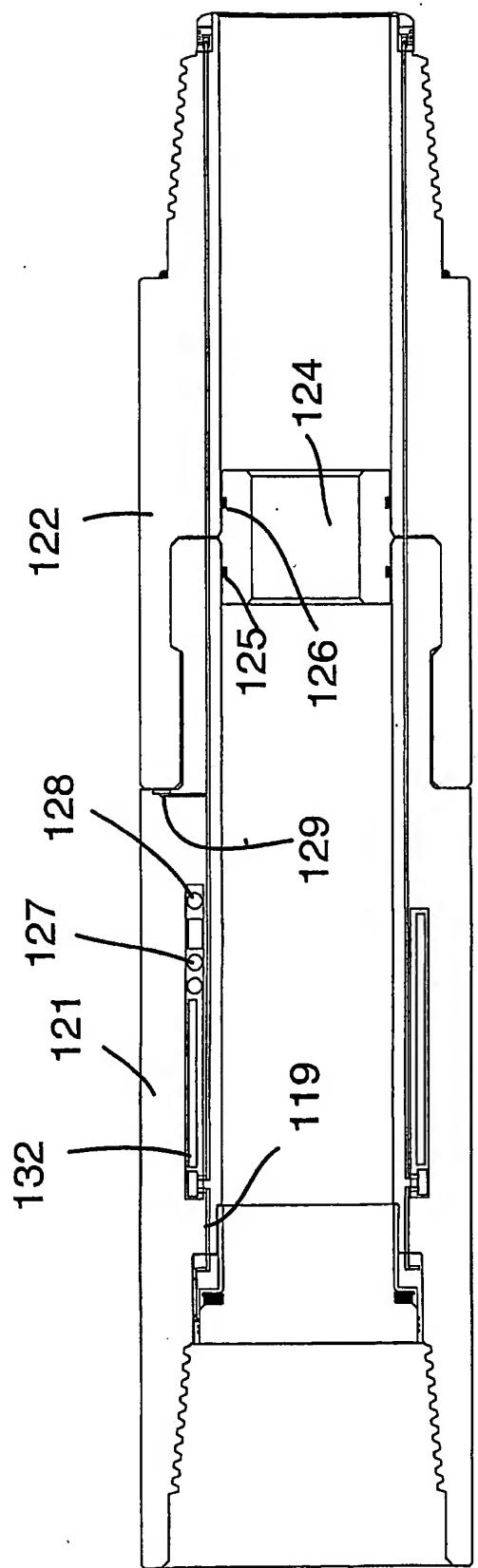


Fig. 14

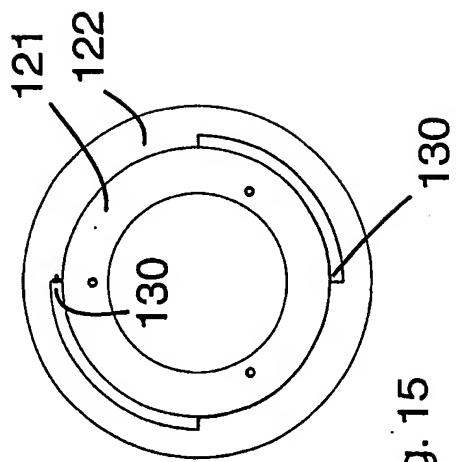


Fig. 15

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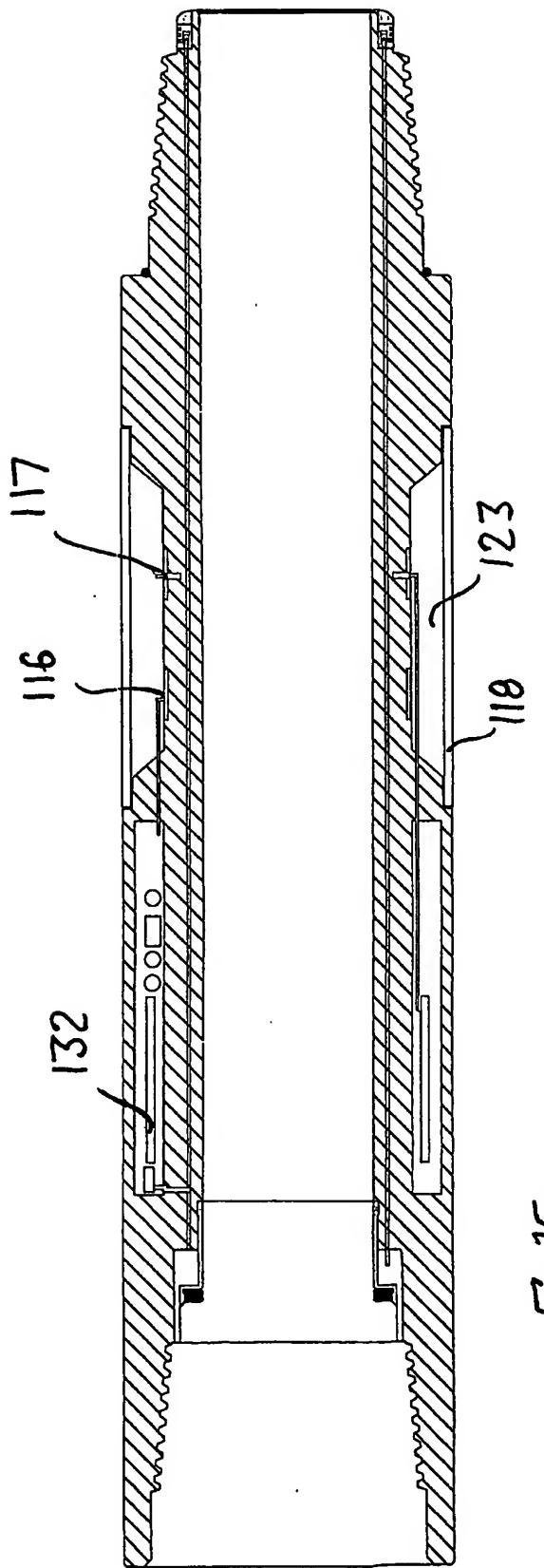


Fig. 15a

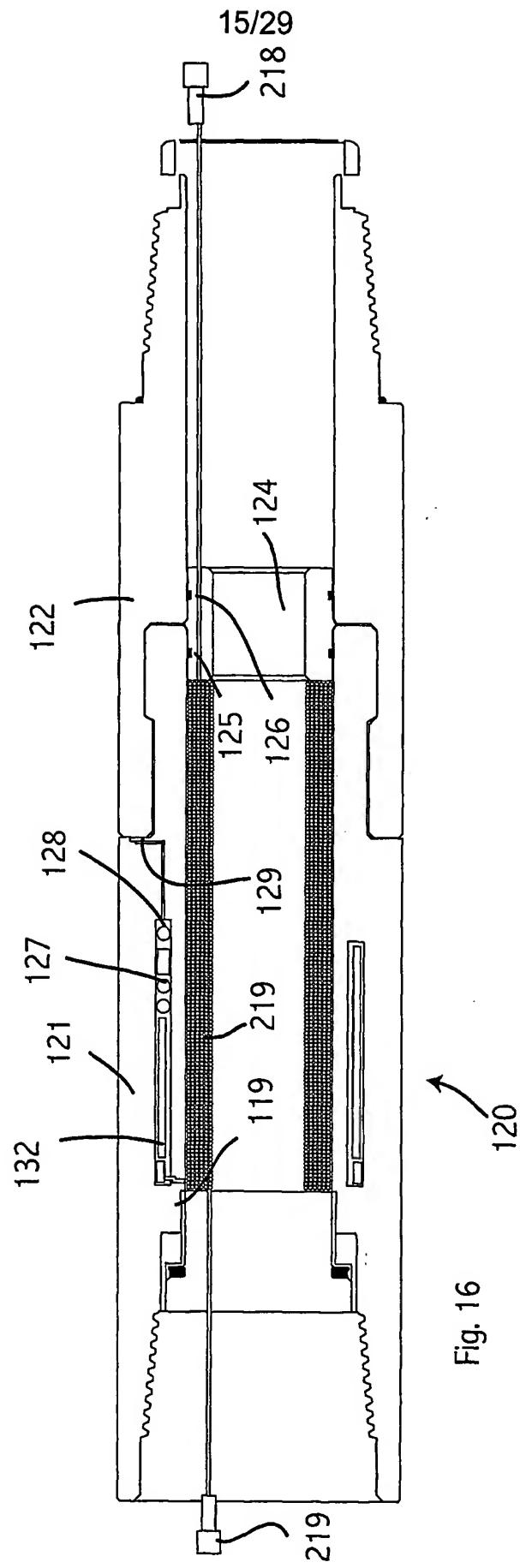


Fig. 16

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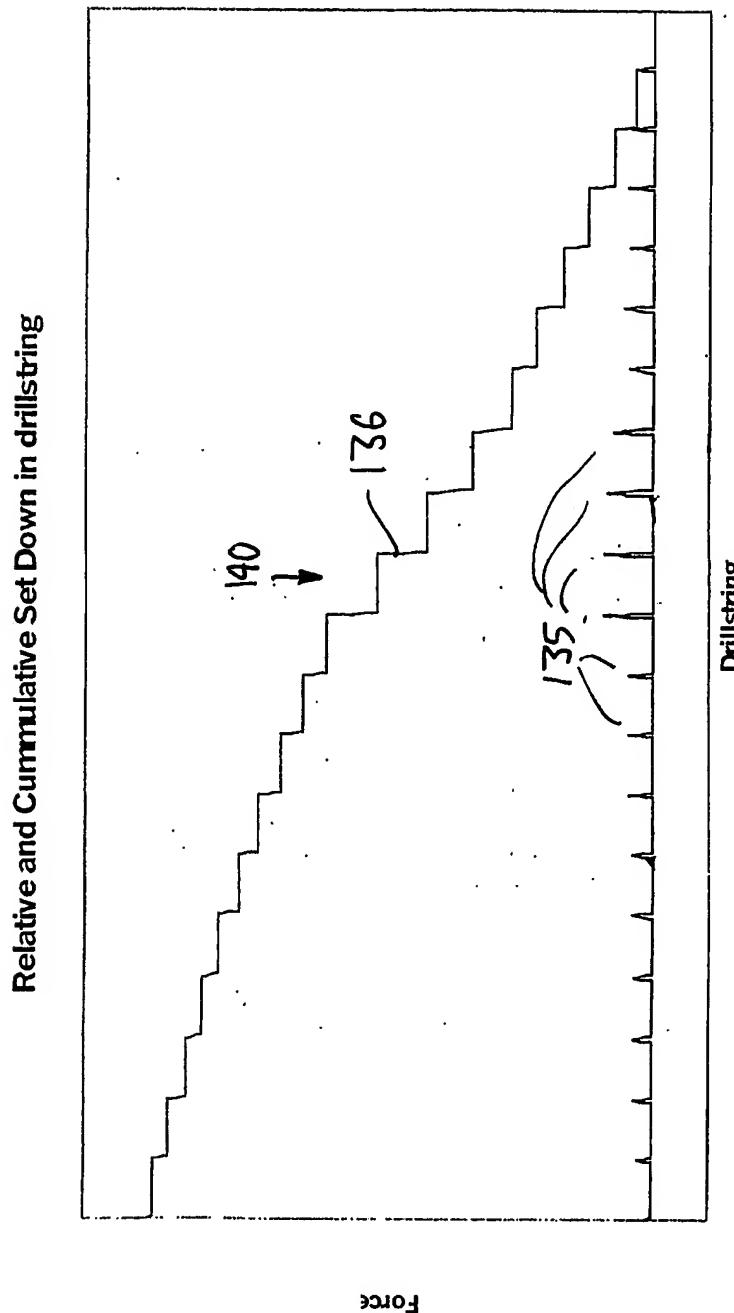


Fig: 17a

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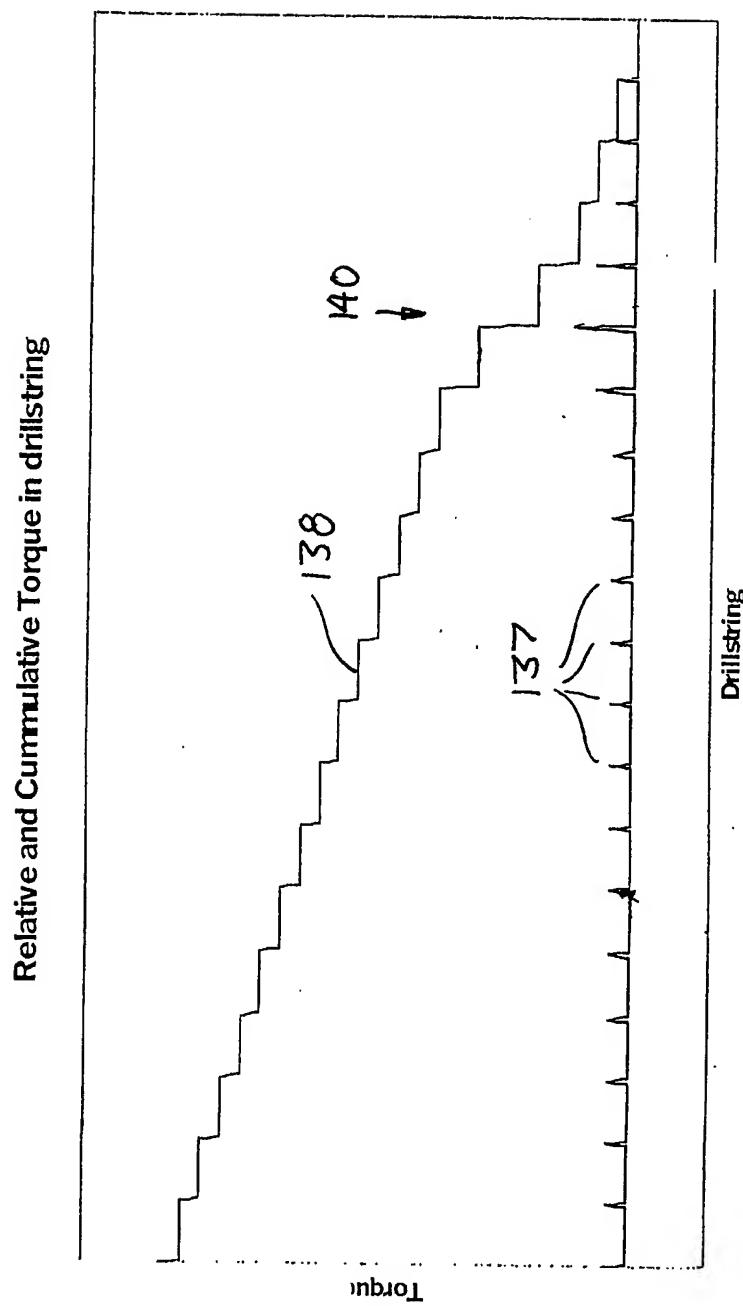


Fig. 17b

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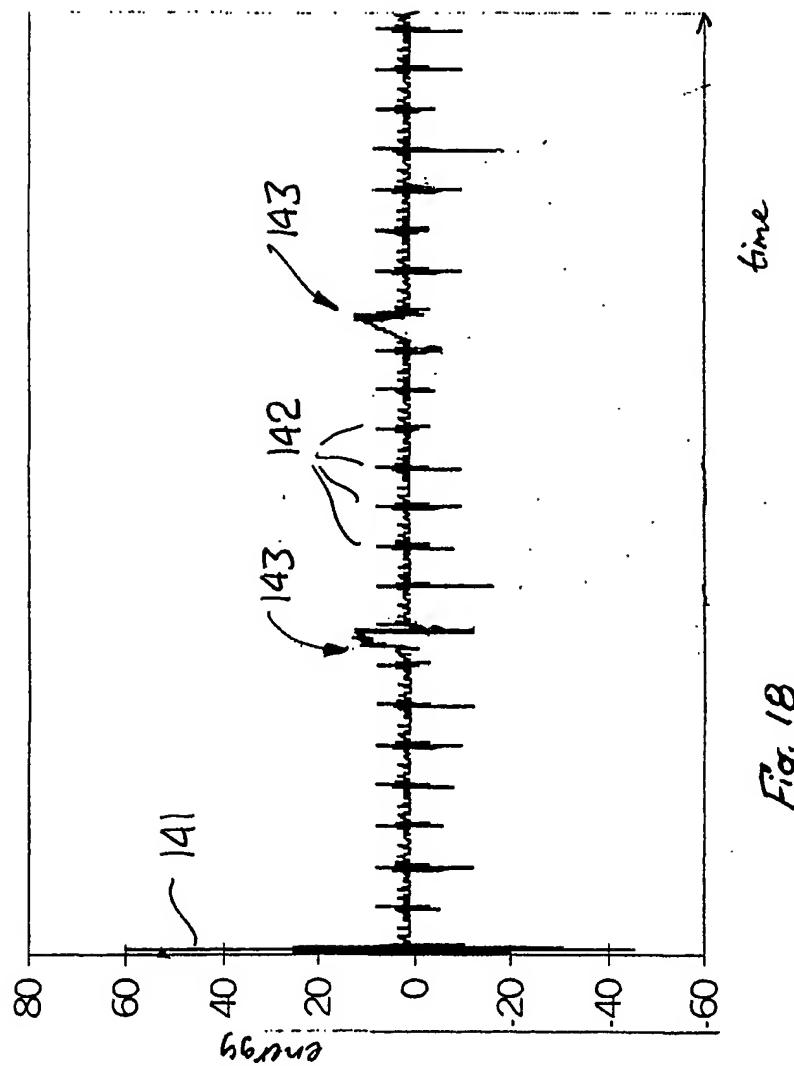


Fig. 18

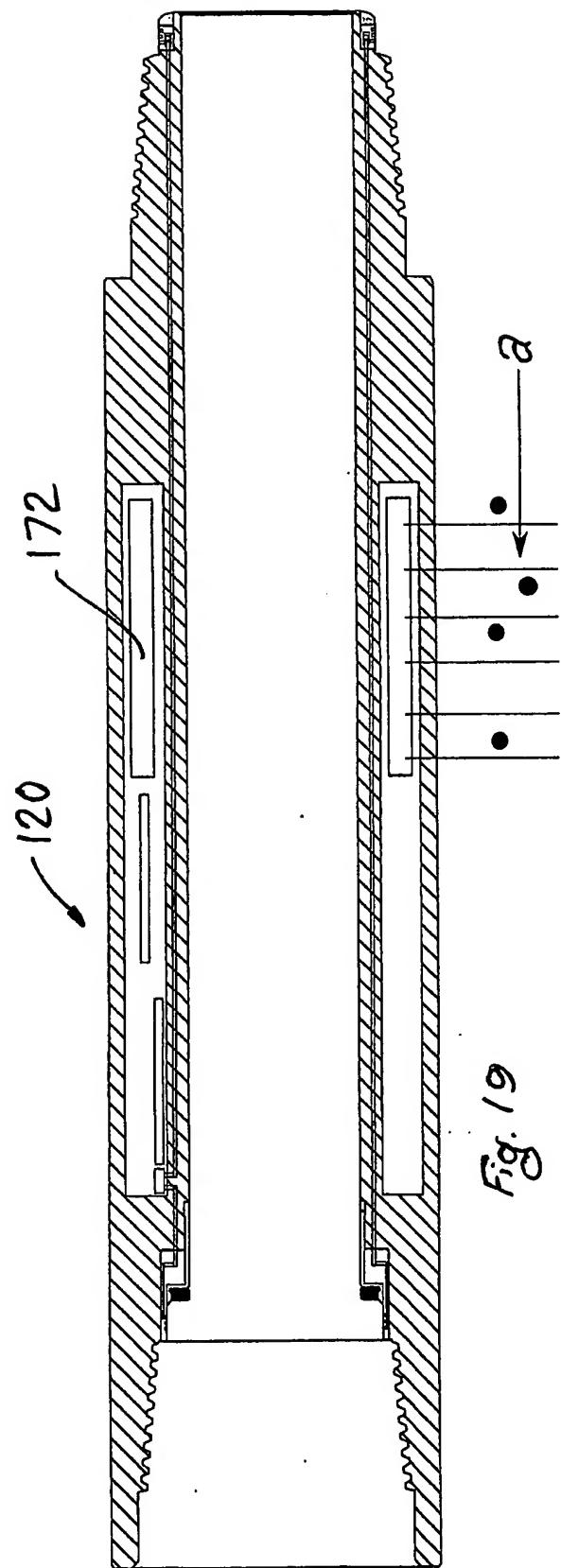


Fig. 19

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Density profile not uniform along hole length, hence Insufficient cuttings being cleared, measured in real time

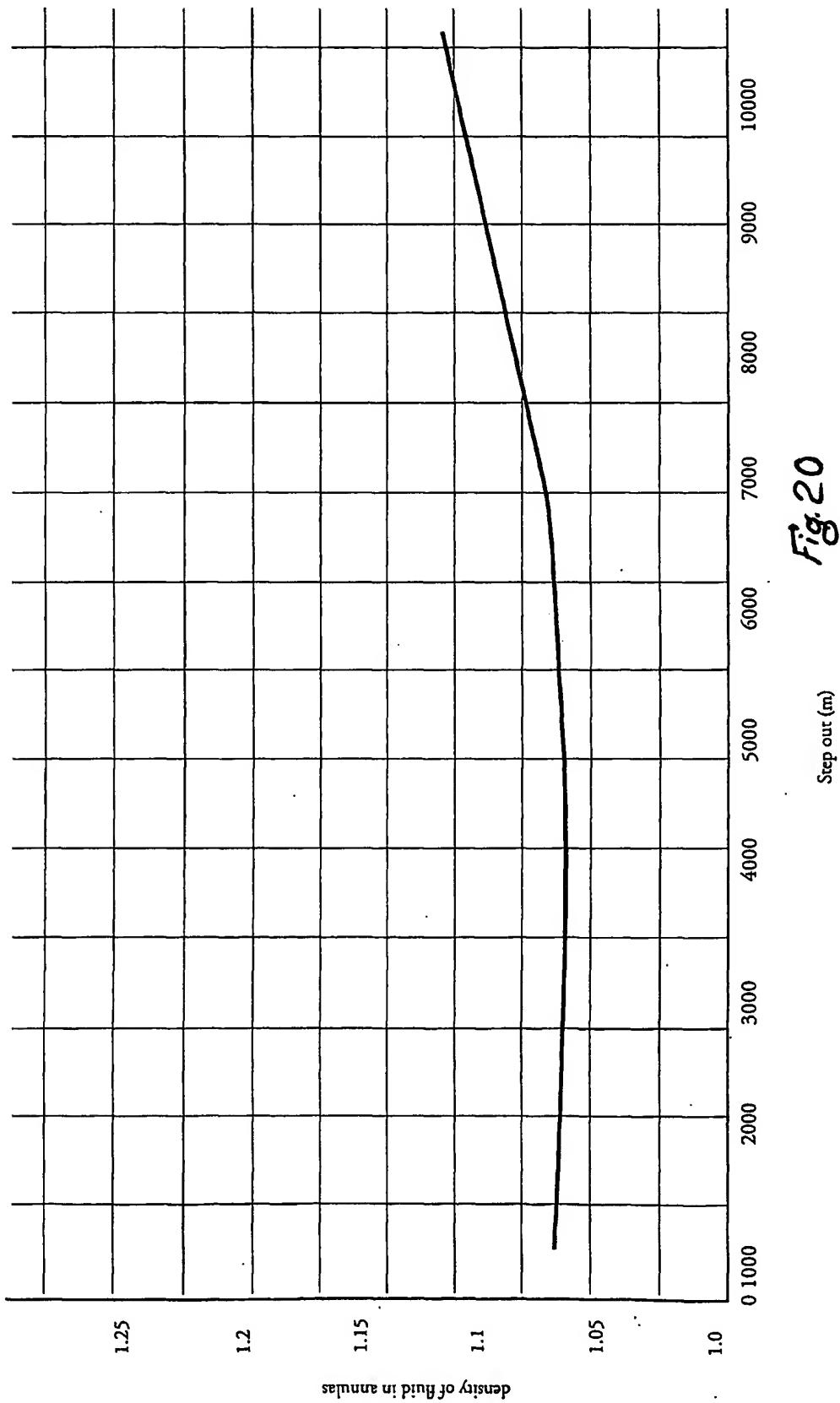


Fig. 20

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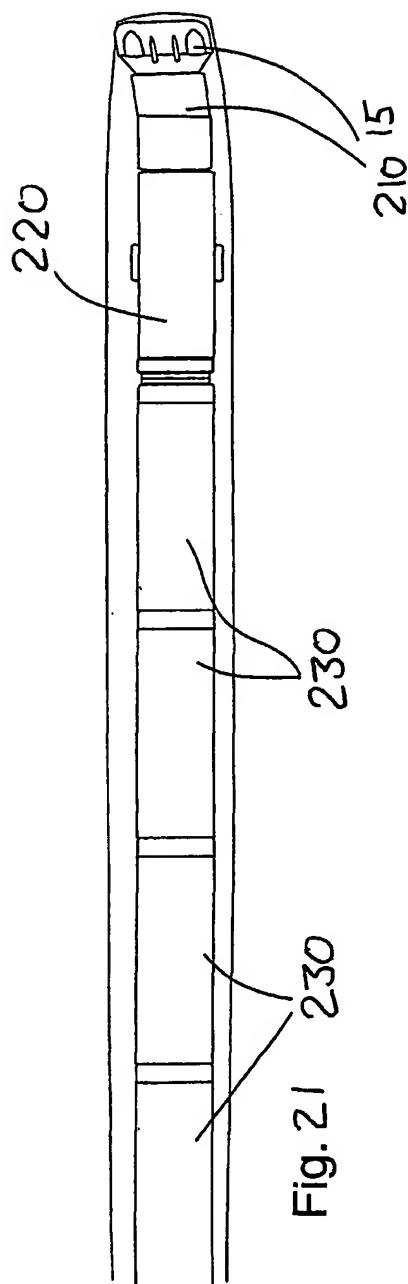


Fig. 21 230

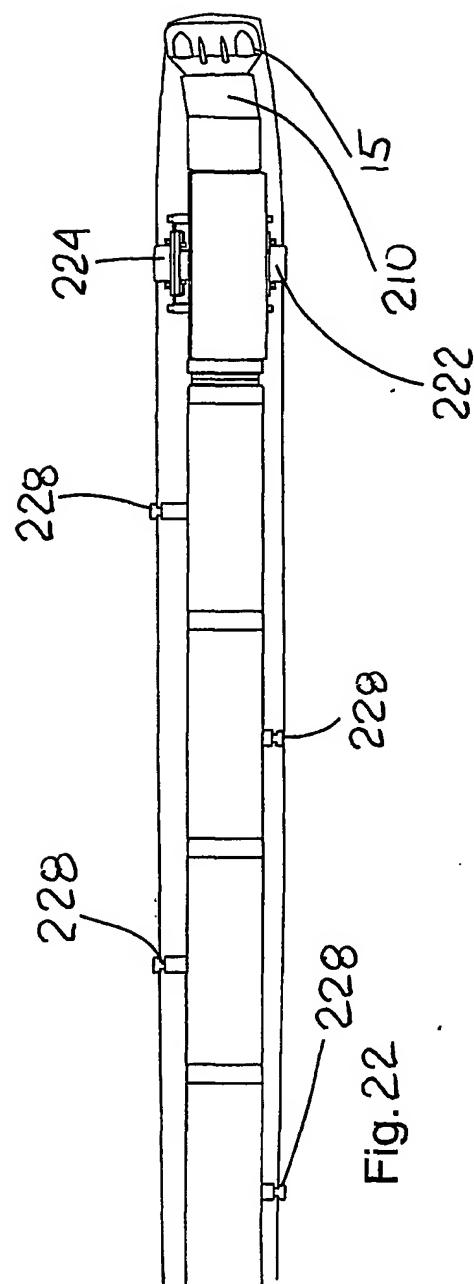


Fig. 22 228 222

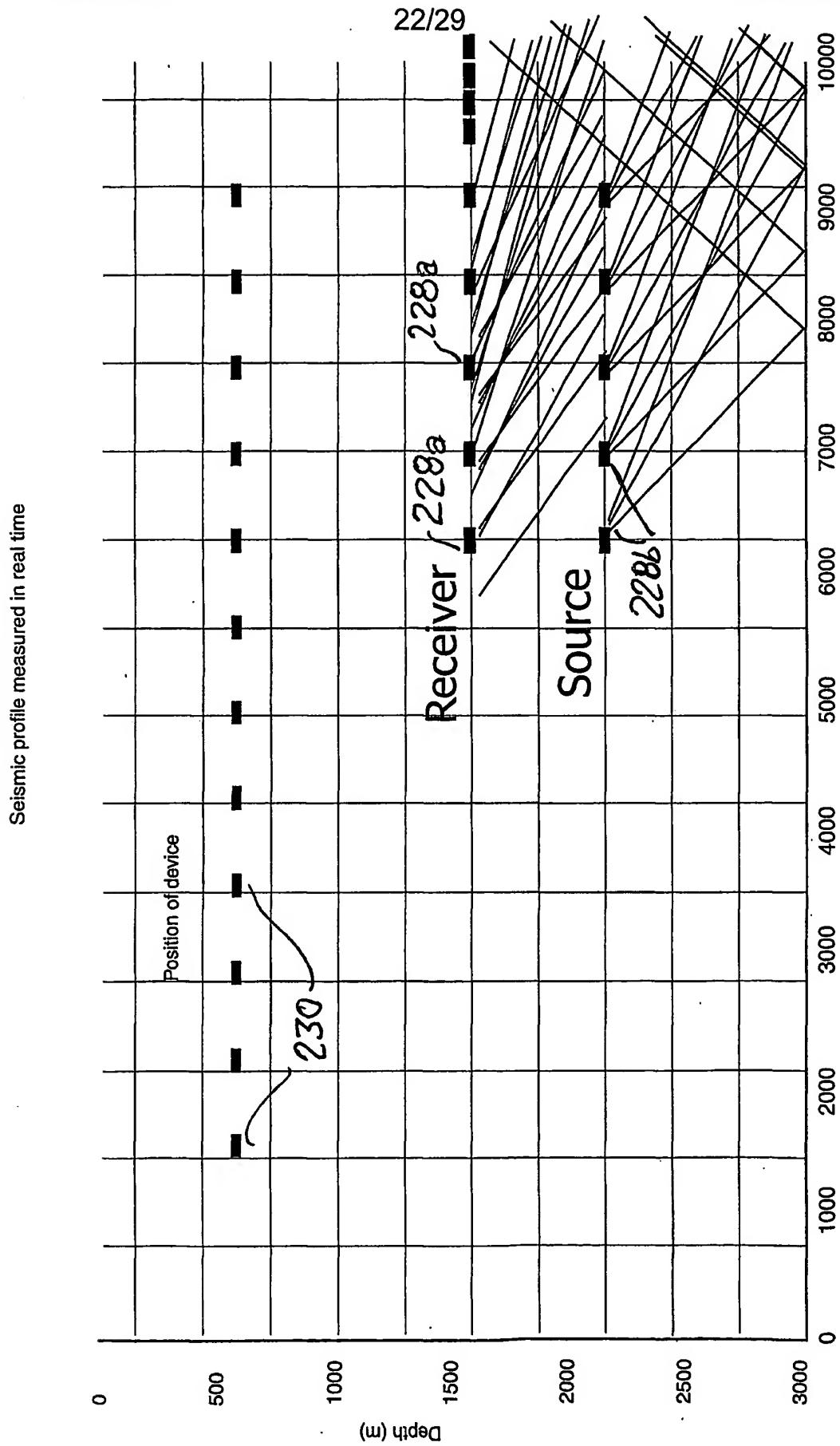


Fig. 23

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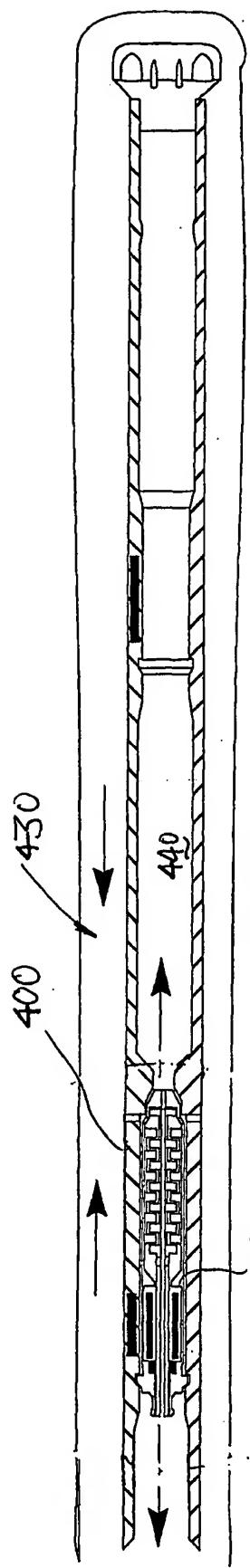


Fig. 24

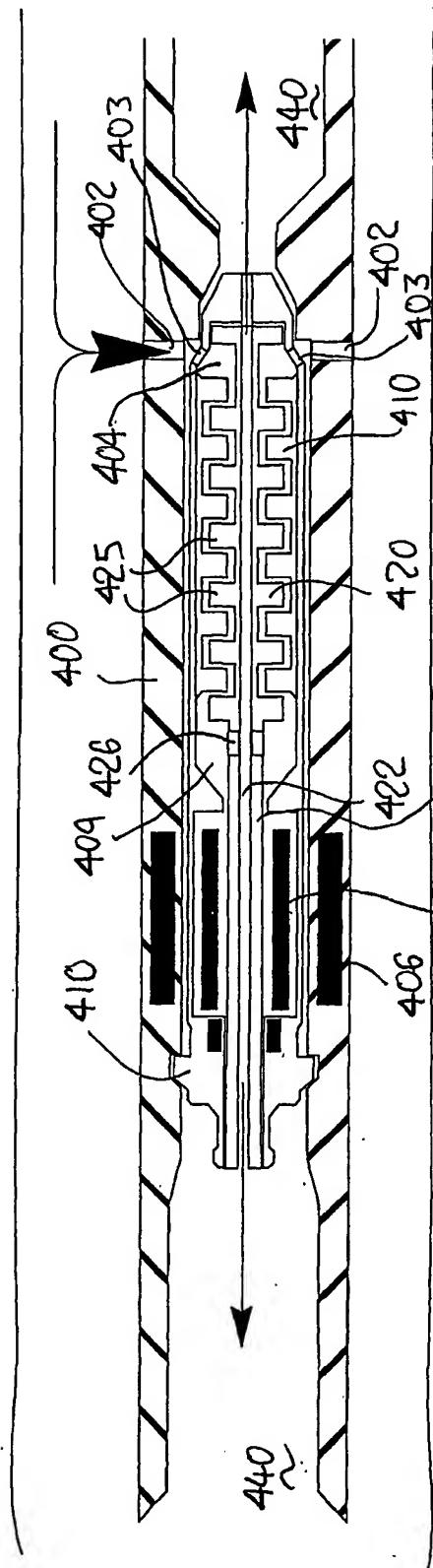


Fig. 25

408

424

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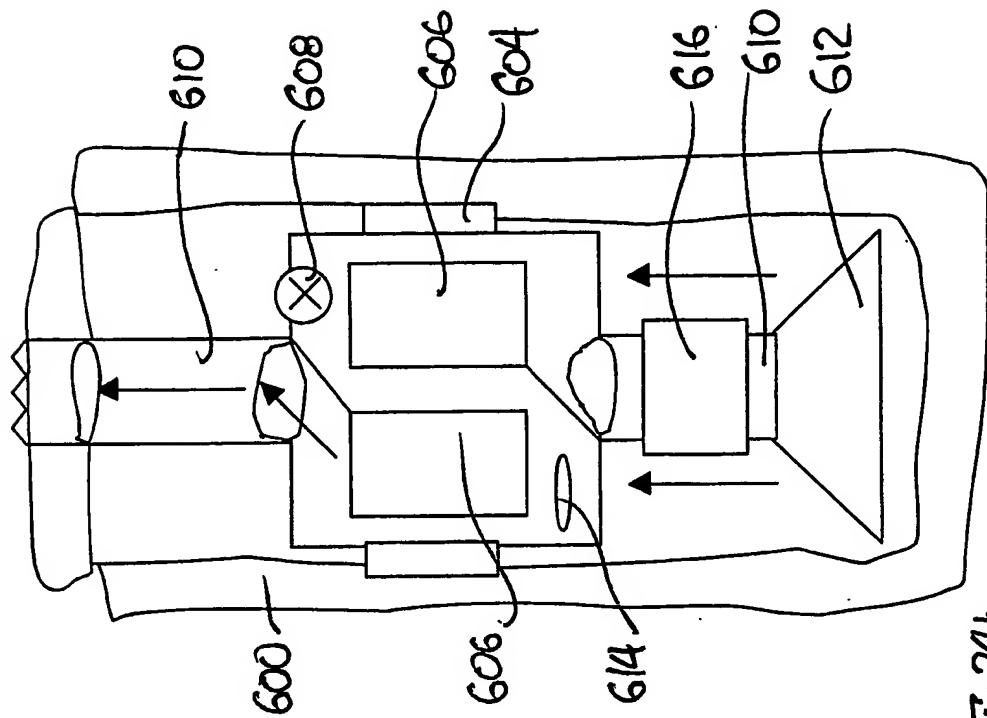


Fig. 24b

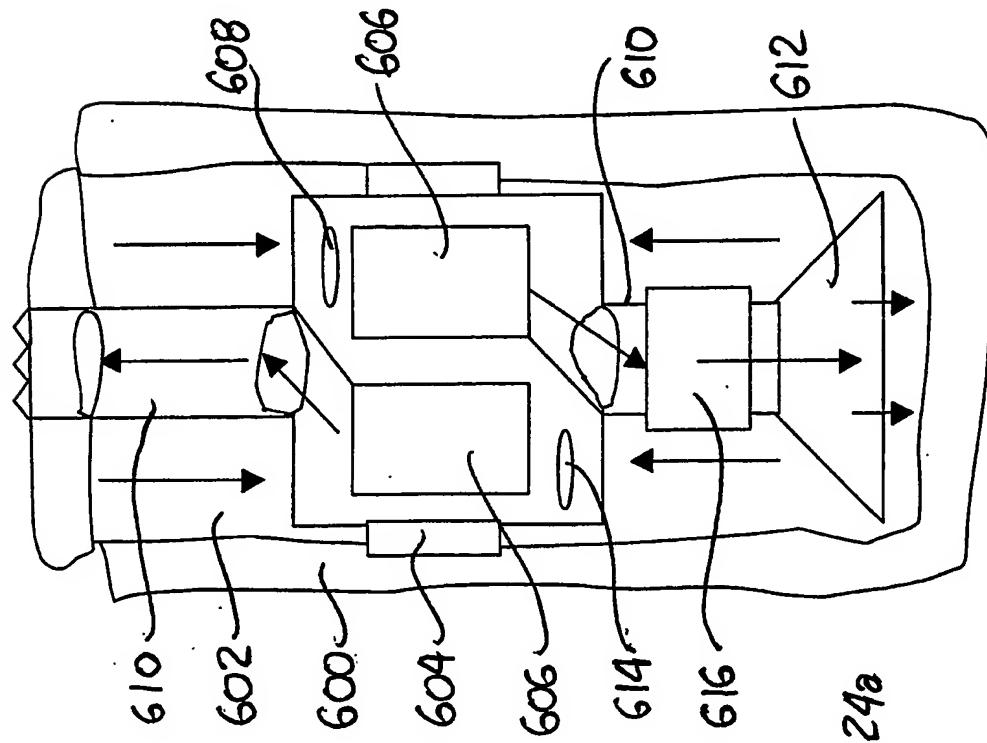
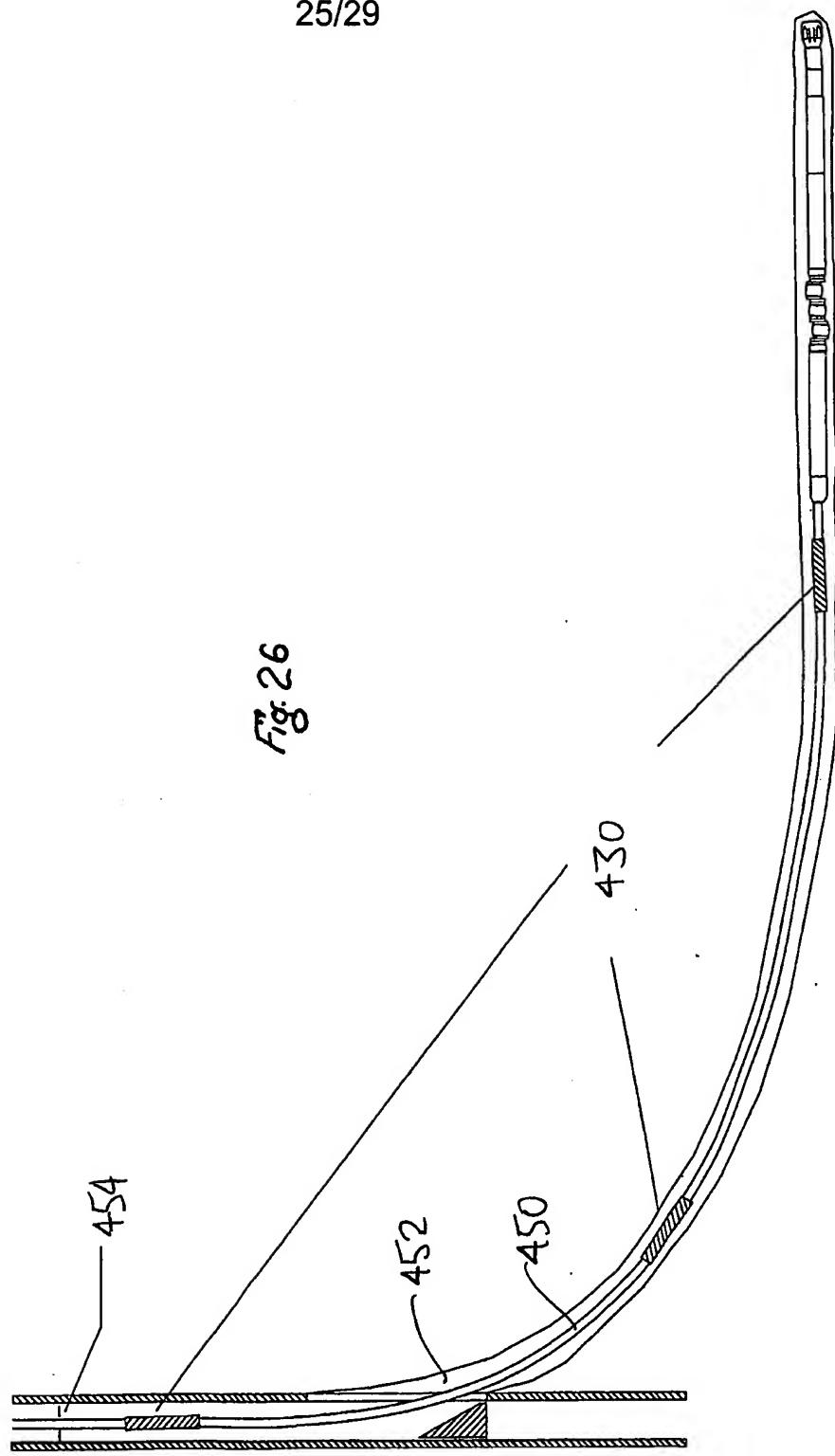


Fig. 24a

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Fig. 26



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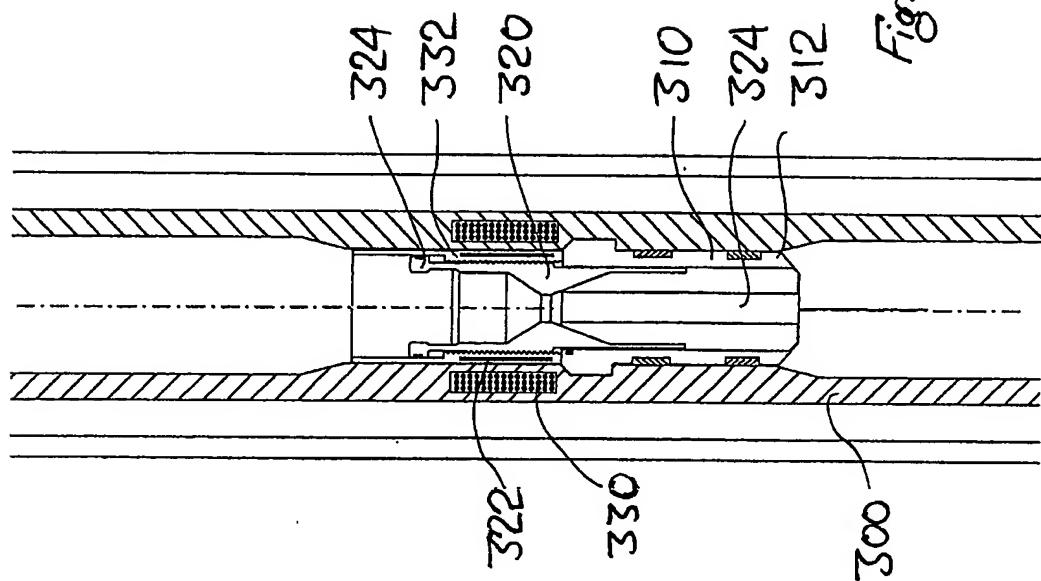


Fig. 27b

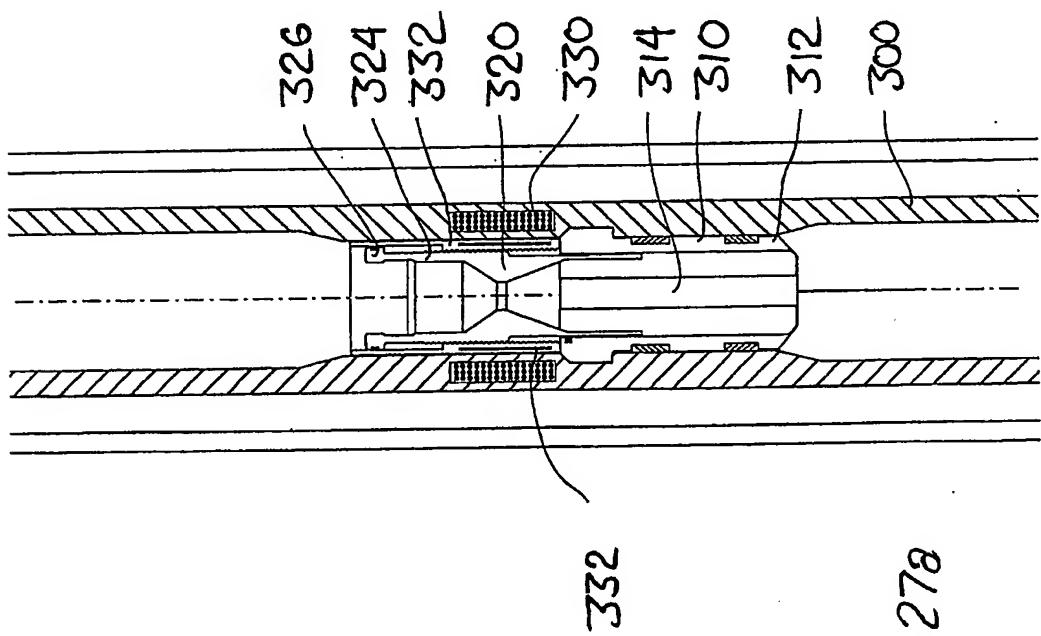


Fig. 278

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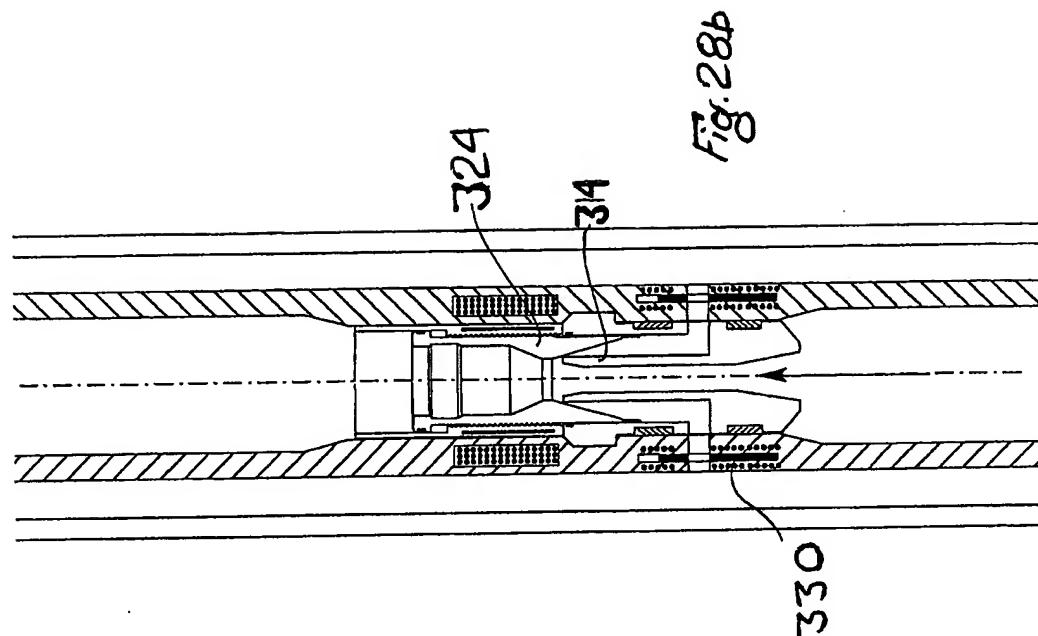


Fig. 28b

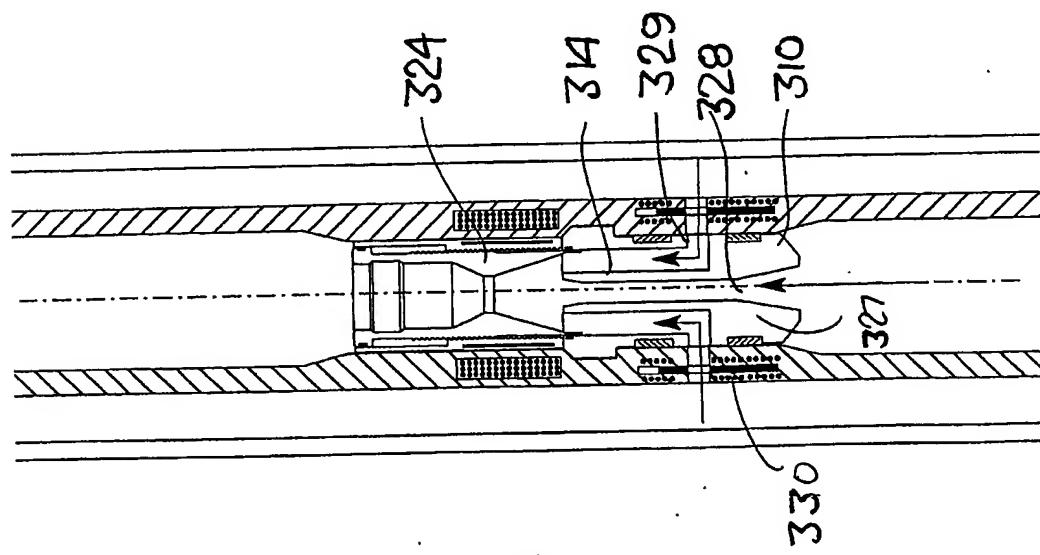
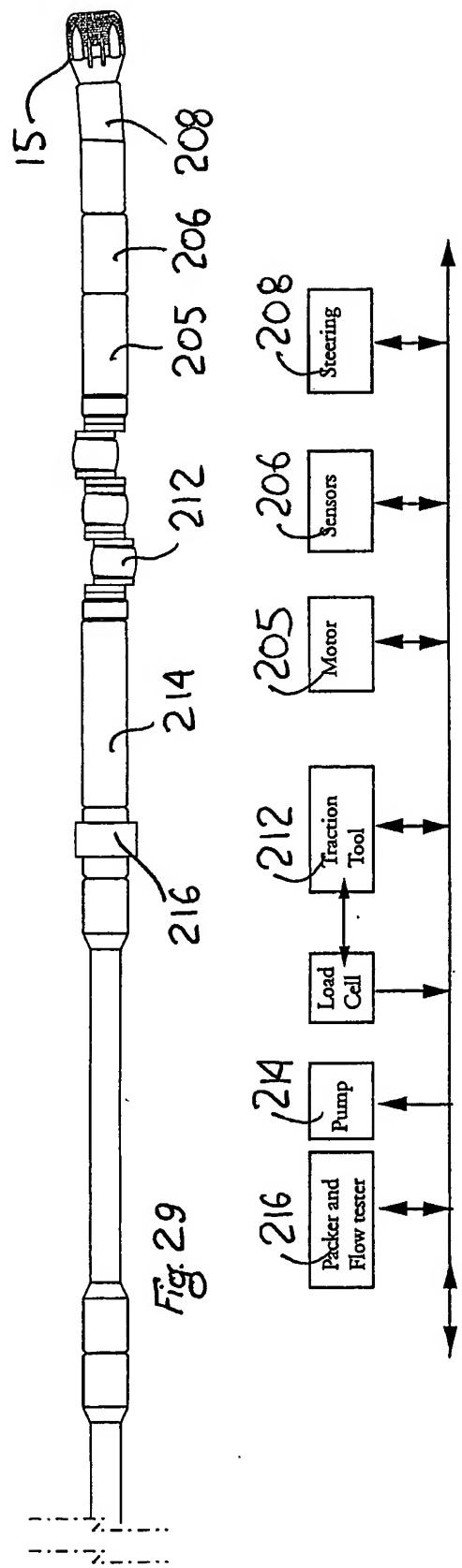


Fig. 28a



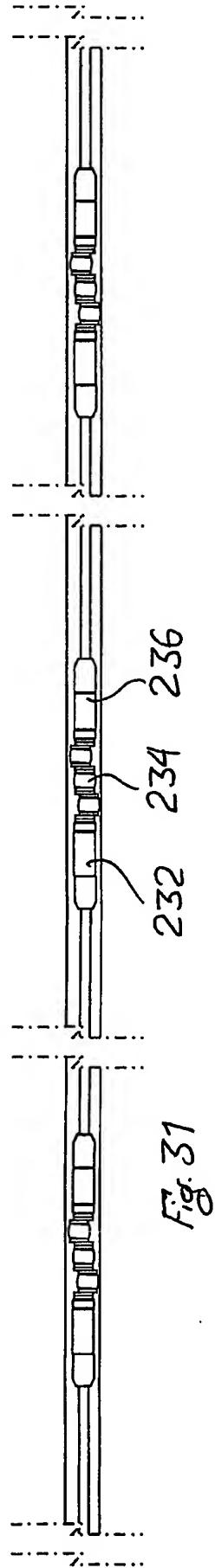


Fig. 31

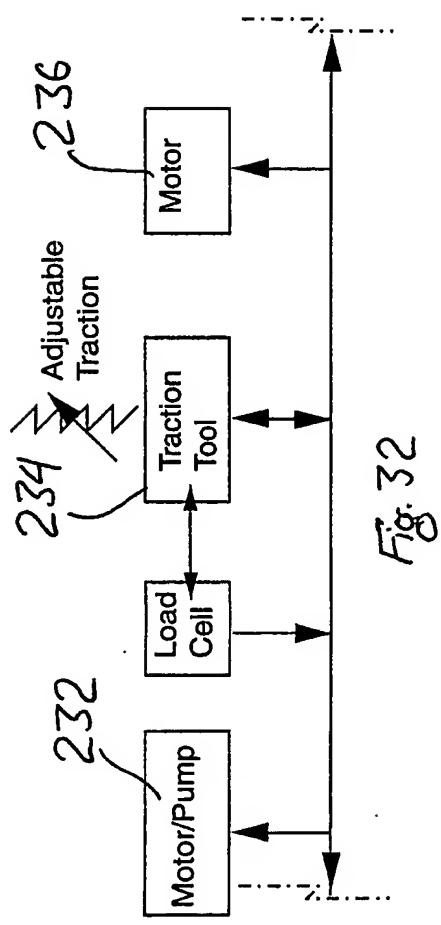


Fig. 32

INTERNATIONAL SEARCH REPORT

Int	tional Application No
PCT/GB 02/03429	

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B31/00 E21B17/00

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)
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C. DOCUMENTS CONSIDERED TO BE RELEVANT
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Category	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 4 799 544 A (CURLETT HARRY B) 24 January 1989 (1989-01-24) column 6, line 51-57 column 10, line 11-30 column 15, line 61-66 column 15, line 14-30 figures 1-4,6,7,18,19	1-4,8,9, 16,19
Y	---	13
Y	US 3 879 097 A (OERTLE DON H) 22 April 1975 (1975-04-22) figure 1	13
A	US 4 384 625 A (ROPER WILBUR F ET AL) 24 May 1983 (1983-05-24) abstract	1,25
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INTERNATIONAL SEARCH REPORT

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Category	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
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INTERNATIONAL SEARCH REPORT

Information on patent family members

Int'l Application No

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